

FLORIDA PUBLIC SERVICE COMMISSION
EXHIBIT INDEX

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FPSC - COMMISSION CLERK

FOR THE HEARING DATED 11/02/2021 IN DOCKET 20210001-EI

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<u>Docket No. 20210001-EI</u> Comprehensive Exhibit List for Entry into Hearing Record November 2, 2021					
EXH#	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
DUKE ENERGY FLORIDA – DIRECT					
2	Gary Dean	GPD-1T	Fuel Cost Recovery True-Up (Jan – Dec. 2020).	1B, 1D, 6-11, 18-22, 23A-23B and 27-36	
3	Gary Dean	GPD-2T	Capacity Cost Recovery True-Up (Jan – Dec. 2020).	1B, 1D, 6-11, 18-22, 23A-23B and 27-36	
4	Gary Dean	GPD-3T	Schedules A1 through A3, A6 and A12 for Dec 2020.	1B, 1D, 6-11, 18-22, 23A-23B and 27-36	
5	Gary Dean	GPD-4T	2020 Capital Structure and Cost Rates Applied to Capital Projects.	1B, 1D, 6-11, 18-22, 23A-23B and 27-36	
6	Gary Dean	GPD-2	Actual/Estimated True-up Schedules for period January – December 2021.	1B, 1D, 6-11, 18-22, 23A-23B and 27-36	
7	Gary Dean	GPD-3	Projection Factors for January - December 2022.	1B, 1D, 6-11, 18-22, 23A-23B and 27-36	
8	Joseph Simpson	JS-1	Root Cause Analysis.	1C	

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9	Joseph Simpson	JS-2	Repair Evaluation Report.	1C	
10	Jim McClay	JM-1P	Hedging Testimony 2022 Risk Management Plan Confidential DN. 08414-2021	1A	
11	Mary Ingle Lewter	MIL-1T	Calculation of GPIF Reward for January - December 2020.	16 and 17	
12	Mary Ingle Lewter	MIL-1P	GPIF Targets/Ranges Schedules for January – December 2022.	16 and 17	
FLORIDA POWER & LIGHT COMPANY – DIRECT					
GULF POWER COMPANY – DIRECT					
13	R. B. Deaton	RBD-1	2020 FCR Final True-Up Calculation.	8, 10	
14	R. B. Deaton	RBD-2	2020 CCR Final True-Up Calculation Confidential DN. 03229-2021	27, 29	
15	R. B. Deaton	RBD-3	2021 FCR Actual/Estimated True-Up Calculation.	9, 10	
16	R. B. Deaton	RBD-4	2021 CCR Actual/Estimated True-Up Calculation.	28, 29	
17	R. B. Deaton	RBD-5	Appendix II Consolidated 2022 FCR Projections.	11, 18-22, 34-36	
18	R. B. Deaton	RBD-6	Appendix III-A Revised 2021 FCR Actual/Estimated True-Up Calculation – FPL Appendix III-B Revised 2021 FCR Actual/Estimated True-Up Calculation – Gulf	9, 10	

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19	R. B. Deaton	RBD-7	Appendix IV Consolidated 2022 CCR Projections.	30-36	
20	R. B. Deaton	RLH-1	2020 FCR Final True-Up Calculation.	8, 10	
21	R. B. Deaton	RLH-2	2020 CCR Final True-Up Calculation.	27, 29	
22	R. B. Deaton	RLH-3	2021 FCR Actual/Estimated True-Up Calculation.	9, 10	
23	R. B. Deaton	RLH-4	2021 CCR Actual/Estimated True-Up Calculation.	28, 29	
24	G. J. Yupp	GJY-1	2020 Asset Optimization Program Results. Confidential DN. 03229-2021	2C- 2F	
25	G. J. Yupp	GJY-2	2022 Risk Management Plan. Confidential DN. 08350-2021	2H and 4A	
26	G. J. Yupp	GJY-2S	2022 Risk Management Plan.	2H and 4A	
27	G. J. Yupp	GJY-3	Appendix I Consolidated Fuel Cost Recovery.	6-11 and 18	
28	C. R. Rote	CRR-1	Generating Performance Incentive Factor Performance Results for January 2020 through December 2020.	16	
29	C. R. Rote	CR-1	Generating Performance Incentive Factor Performance Results for January 2020 through December 2020.	16	

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EXH#	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
30	C. R. Rote	CCR-2	Generating Performance Incentive Factor Performance Results for January 2020 through December 2020.	16	
31	C. R. Rote	CRR-2	Generating Performance Incentive Factor Consolidated Performance Targets for January 2022 through December 2022.	17	
32	J. Chin	JC-1	2019 OCEC Final Revenue Requirement Calculation.	24D	
33	J. Chin	JC-2	2019 SoBRA Final Revenue Requirement Calculation.	24A	
34	J. Chin	JC-3	2020 SoBRA Final Revenue Requirement Calculation.	24B	
35	E. J. Anderson	EJA-1	Revised Okeechobee Factor/Refund Calculation.	2I and 24D	
36	E. J. Anderson	EJA-2	Revised 2019 SoBRA Factor/Refund Calculation.	2A and 24A	
37	E. J. Anderson	EJA-3	Revised 2020 SoBRA Factor/Refund Calculation.	2A and 24B	
FLORIDA PUBLIC UTILITIES COMPANY - DIRECT					
38	Curtis D. Young	CDY-1	Final True Up Schedules (Schedules A, C1 and E1-B for FPUC's Divisions)	8	
39	Curtis D. Young	CDY-2	Estimated/Actual (Schedules El-A, El-B, and El-B1)	3A, 9	

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40	Curtis D. Young	CDY-3	Schedules E1, E1A, E2, E7, E8, E10 and Schedule A	10, 11, 18, 19, 20, 21, 22, 34, 35, 36	
TAMPA ELECTRIC COMPANY - DIRECT					
41	M. Ashley Sizemore	MAS-1 (Revised)	Final True-up Capacity Cost Recovery January 2020 – December 2020. Final True-up Fuel Cost Recovery January 2020 – December 2020. Actual Fuel True-up Compared to Original Estimates January 2020 – December 2020. Schedules A-1, A-2, A-6 through A-9, and A-12. January 2020 – December 2020. Capital Projects Approved for Fuel Clause Recovery January 2020 – December 2020. Revised July 23, 2021	8, 10, 27, 29	
42	M. Ashley Sizemore	MAS-2	Actual/Estimated True-Up Fuel Cost Recovery January 2021 – December 2021. Actual/Estimated True-Up Capacity Cost Recovery January 2021 – December 2021.	9, 10, 28, 29	
43	M. Ashley Sizemore	MAS-3	Projected Capacity Cost Recovery January 2022 – December 2022. Projected Fuel Cost Recovery January 2022 – December 2022. Levelized and Tiered Fuel Rate January 2022 – December 2022. Confidential DN. 10095-2021	11, 18 – 22, 30 - 36	

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EXH#	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
44	M. Ashley Sizemore	MAS-4	Projected Capacity Cost Recovery using the 2021 Settlement Agreement Methodology January 2022 – December 2022. Projected Fuel Cost Recovery using the 2021 Settlement Agreement Methodology January 2022 – December 2022.	11, 18-22, 30-36	
45	Patrick A. Bokor	PAB-1	Final True-Up Generating Performance Incentive Factor January 2020 – December 2020. Actual Unit Performance Data January 2020 – December 2020.	16	
46	Patrick A. Bokor	PAB-2	Generating Performance Incentive Factor January 2022 – December 2022. Summary of Generating Performance Incentive Factor Targets January 2022 – December 2022.	17	
47	John C. Heisey	JCH-1	Optimization Mechanism Results January 2020 – December 2020.	5A	
48	John C. Heisey	JCH-2	Risk Management Plan January 2022 – December 2022.	No Issues	

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STAFF HEARING EXHIBITS					
49	Young	Staff Exhibit 49	FPUC's Responses to Staff's First Set of Interrogatories, Nos. 1-3. (Bates No. 00001-00018)	3A, 8-10, 18-20, 22	
50	McClay: 1A. Dean: 8-10, 18-20, 22.	Staff Exhibit 50	DEF's Response to Staff's Third Set of Interrogatories, Nos. 3-4. (Bates No. 00019-00023)	1A, 8-10, 18-20, 22	
51	Valle	Staff Exhibit 51	FPL's Response to Staff's Third Set of Interrogatories, No. 7 (7-Supplemental) (Including attachment) (Bates No. 00024-00027)	2G	
52	Young	Staff Exhibit 52	FPUC's Responses to Staff's Second Set of Interrogatories, Nos. 4-5. (Bates No. 00028-00031)	3A, 8-10, 18-20, 22	
53		Staff Exhibit 53	DEF's Response to Staff's First Request to Produce Documents, No. 1. (Including attachment) (Bates No. 00032-00042)	8-10, 18-20, 22	
54	Dean: 8,10 Lewter: 9 Simpson: 11, 12, 13, 15	Staff Exhibit 54	DEF's Responses to Staff's Fifth Set of Interrogatories, Nos. 8-14. (Bates No. 00043-00124)	8-10, 18-20, 22	
55	Sizemore	Staff Exhibit 55	TECO's Response to Staff's Second Set of Interrogatories, No. 4. (Bates No. 00125-00127)	8-10, 18-20, 22	
56	Yupp	Staff Exhibit 56	FPL's Response to Staff's Sixth Set of Interrogatories, No. 15. (Bates No. 00128-00130)	8-10, 18-20, 22	

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EXH#	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
57	Yupp	Staff Exhibit 57	FPL's Response to Staff's Seventh Set of Interrogatories, No. 16. (Bates No. 00131-00132)	8-10, 18-20, 22	
58		Staff Exhibit 58	DEF's Response to OPC's First Request to Produce Documents, Nos. 1, 3, 4. (Bates No. 00133-00146)	8-10, 18-20, 22	
59	Dean: 2, 3, 6, and 7. Lewter: 1, 5. Swartz: 4, 8.	Staff Exhibit 59	DEF's Response to OPC's First Set of Interrogatories, Nos. 1-8. (Bates No. 00147-00150)	8-10, 18-20, 22	
60		Staff Exhibit 60	DEF's Response to OPC's Second Request to Produce Documents, No. 5-6. (Including attachment to No. 5) (Bates No. 00151-00153)	8-10, 18-20, 22	
61	Dean: 12, 13, 16, and 17. Lewter: 15. Swartz: 11, 14, and 18.	Staff Exhibit 61	DEF's Response to OPC's Third Set of Interrogatories, Nos. 11-18. (Bates No. 00154-00160)	8-10, 18-20, 22	
62	Anderson: 19-22, 25, 26, 29-32. Dean: 2, 3, 4, 7, 8.	Staff Exhibit 62	DEF's Response to OPC's Fourth Set of Interrogatories, Nos. 19-32. (Bates No. 00169-00182)	8-10, 18-20, 22	
63	Young	Staff Exhibit 63	FPUC Responses to OPC's First Set of Interrogatories, Nos. 1-5. (Including attachments) (Revised responses to Nos. 1-2) (Bates No. 00169-00182)	3A, 8-10, 18-20, 22	

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64	Simpson	Staff Exhibit 64	DEF's Supplemental Responses to OPC's First Set of Interrogatories No. 8. DEF's Supplemental Responses to OPC's First Set of Production of Documents No. 4. (Bates No. 00183-00265)		
65		Staff Exhibit 65	Proposed Stipulations (Bates No. 00266-00290)		
66		Staff Exhibit 66	Gerald Yupp October 20, 2021, Deposition and errata sheet. (Bates No. 00291-00340)		
67		Staff Exhibit 67	DEF's response to Staff's Fourth Interrogatories Nos. 5-7. (Bates No. 003411-00345)		

Duke Energy Florida, LLC
Fuel Adjustment Clause
Summary of Actual True-Up Amount
January 2020 - December 2020

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional kWh Sales - Difference	519,013,560
2	Non-Jurisdictional kWh Sales - Difference	(17,944,081)
3	Total System kWh Sales - Difference Schedule A2, pg 1 of 2, line B3	<u>501,069,479</u>
	System:	
4	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C4	<u>\$ 58,343,610</u>
	Jurisdictional:	
5	Fuel Revenues - Difference Schedule A2, page 2 of 2, line C3	\$19,109,180
6	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C6 - C12 - C7	<u>(102,295,503)</u>
7	True-Up Amount for the Period	121,404,683
8	True-Up for the Prior Period Schedule A2, page 2 of 2, line C9	(35,997,914)
9	True-Up Collected/(Refunded) in Current Period	(63,769,101)
10	Interest Provision Schedule A2, page 2 of 2, line C8	<u>(58,082)</u>
11	Actual True-Up Ending Balance for the Period January 2020 through December 2020 Schedule A2, page 2 of 2, line C13	21,579,587
12	Estimated True-Up Ending Balance for the Period January 2020 through December 2020 as approved in Order No. PSC-2021-0024-FOF-EI	61,083,424
13	Total True-Up for the Period January 2019 through December 2020	<u>\$ (39,503,838)</u>

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2020 - December 2020

		JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB- TOTAL
A	1	Fuel Cost of System Generation	\$ 74,992,301	\$ 65,717,824	\$ 73,293,028	\$ 70,415,016	\$ 87,128,507	\$ 461,255,106
	2	Fuel Cost of Power Sold	(1,105,818)	(1,159,871)	(1,312,152)	(2,612,318)	(5,495,100)	(18,291,367)
	3	Fuel Cost of Purchased Power	1,777,132	3,137,635	6,173,029	1,917,858	6,444,417	29,247,948
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	7,319,413	7,093,012	5,551,577	5,410,902	7,518,681	40,321,435
	4	Energy Cost of Economy Purchases	143,759	406,521	1,053,448	485,384	407,645	2,685,678
	5	Adjustments to Fuel Cost	(12,011,163)	1,119,402	1,152,738	1,147,328	1,139,918	(6,309,342)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	<u>71,115,625</u>	<u>76,314,523</u>	<u>85,911,668</u>	<u>76,764,171</u>	<u>97,146,585</u>	<u>508,909,459</u>
B	1	Jurisdictional MWH Sales	2,640,092	2,661,153	2,818,044	3,239,131	2,981,765	17,790,571
	2	Non-Jurisdictional MWH Sales	14,426	18,358	26,409	25,344	19,970	130,469
	3	TOTAL SALES (Lines B1 + B2)	<u>2,654,517</u>	<u>2,679,511</u>	<u>2,844,452</u>	<u>3,264,474</u>	<u>3,001,736</u>	<u>17,921,040</u>
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.46%	99.31%	99.07%	99.22%	99.33%	99.27%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	85,968,564	86,669,575	91,874,742	103,746,698	25,329,422	509,178,083
	2	True-Up Provision	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	77,026,561	71,000,441
	2a	Incentive Provision	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(1,295,849)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	<u>84,547,365</u>	<u>85,248,376</u>	<u>90,453,544</u>	<u>102,325,499</u>	<u>102,140,009</u>	<u>578,882,675</u>
	4	Fuel & Net Power Transactions (Line A6)	71,115,625	76,314,523	85,911,668	76,764,171	97,146,585	508,909,459
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	<u>70,755,650</u>	<u>75,811,447</u>	<u>85,139,074</u>	<u>76,189,021</u>	<u>96,525,617</u>	<u>505,346,546</u>
	6	Over/(Under) Recovery (Line 3 - Line 5)	13,791,716	9,436,929	5,314,469	26,136,478	5,614,392	73,536,129
	7	Interest Provision	(38,474)	(20,905)	(11,239)	9,273	(736)	(65,341)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	<u>13,753,242</u>	<u>9,416,024</u>	<u>5,303,232</u>	<u>26,145,751</u>	<u>5,613,656</u>	<u>73,470,791</u>
	9	Plus: Prior Period Balance	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)
	10	Plus: Cumulative True-Up Provision	1,205,224	2,410,448	3,615,672	4,820,897	(72,205,665)	(71,000,441)
	11	Subtotal Prior Period True-up	(34,792,690)	(33,587,466)	(32,382,242)	(31,177,017)	(108,203,579)	(106,998,354)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	<u>(21,039,449)</u>	<u>(10,418,201)</u>	<u>(3,909,747)</u>	<u>\$23,441,228</u>	<u>(\$47,971,677)</u>	<u>(33,527,567)</u>

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2020 - December 2020

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	\$ 101,770,540	\$ 103,341,889	\$ 114,361,759	\$ 104,146,362	\$ 93,419,938	\$ 96,045,352	\$ 1,074,340,946
	2	Fuel Cost of Power Sold	(6,002,918)	(7,637,749)	(7,168,120)	(9,177,223)	(4,434,080)	(6,489,729)	(59,201,186)
	3	Fuel Cost of Purchased Power	6,656,470	7,942,006	4,520,438	6,677,913	5,141,086	5,614,657	65,800,518
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	7,056,004	7,544,093	7,481,269	6,785,867	7,614,778	8,161,873	84,965,318
	4	Energy Cost of Economy Purchases	226,752	442,514	(236,788)	655,147	458,419	517,065	4,748,788
	5	Adjustments to Fuel Cost	1,122,738	1,649,538	1,158,077	1,120,974	1,115,887	4,072,496	3,930,368
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	<u>110,829,587</u>	<u>113,282,290</u>	<u>120,116,635</u>	<u>110,209,040</u>	<u>103,316,030</u>	<u>107,921,713</u>	<u>1,174,584,754</u>
B	1	Jurisdictional MWH Sales	3,988,883	3,895,740	3,891,933	3,470,225	3,306,299	2,896,428	39,240,079
	2	Non-Jurisdictional MWH Sales	31,204	30,243	15,741	14,633	9,666	12,812	244,769
	3	TOTAL SALES (Lines B1 + B2)	<u>4,020,087</u>	<u>3,925,983</u>	<u>3,907,674</u>	<u>3,484,858</u>	<u>3,315,965</u>	<u>2,909,241</u>	<u>39,484,848</u>
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.22%	99.23%	99.60%	99.58%	99.71%	99.56%	99.38%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	135,605,102	131,949,296	131,501,964	116,073,927	109,505,466	94,186,011	1,227,999,849
	2	True-Up Provision	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	63,769,101
	2a	Incentive Provision	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(2,591,697)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	<u>134,183,903</u>	<u>130,528,097</u>	<u>130,080,766</u>	<u>114,652,729</u>	<u>108,084,268</u>	<u>92,764,813</u>	<u>1,289,177,253</u>
	4	Fuel & Net Power Transactions (Line A6)	110,829,587	113,282,290	120,116,635	110,209,040	103,316,030	107,921,713	1,174,584,756
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	<u>109,999,206</u>	<u>112,444,863</u>	<u>119,673,256</u>	<u>109,780,185</u>	<u>103,048,349</u>	<u>107,480,166</u>	<u>1,167,772,572</u>
	6	Over/(Under) Recovery (Line 3 - Line 5)	24,184,698	18,083,234	10,407,510	4,872,545	5,035,918	(14,715,353)	121,404,681
	7	Interest Provision	(2,083)	150	1,356	1,806	3,196	2,833	(58,082)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	<u>24,182,615</u>	<u>18,083,384</u>	<u>10,408,867</u>	<u>4,874,351</u>	<u>5,039,115</u>	<u>(14,712,520)</u>	<u>121,346,599</u>
	9	Plus: Prior Period Balance	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)
	10	Plus: Cumulative True-Up Provision	<u>(69,795,217)</u>	<u>(68,589,994)</u>	<u>(67,384,770)</u>	<u>(66,179,546)</u>	<u>(64,974,323)</u>	<u>(63,769,099)</u>	<u>(63,769,099)</u>
	11	Subtotal Prior Period True-up	<u>(105,793,131)</u>	<u>(104,587,908)</u>	<u>(103,382,684)</u>	<u>(102,177,460)</u>	<u>(100,972,237)</u>	<u>(99,767,013)</u>	<u>(99,767,013)</u>
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	<u>(\$8,139,729)</u>	<u>\$11,148,879</u>	<u>\$22,762,970</u>	<u>\$28,842,544</u>	<u>\$35,086,883</u>	<u>\$21,579,587</u>	<u>21,579,587</u>

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of 2018 Actual/Estimated True-up
January 2020 - December 2020 (Filed 7/27/20, Revised 9/2/20)

			JAN	FEB	MAR	APR	MAY	JUN	6 MONTH SUB-
			ACTUAL	ACTUAL	ACTUAL	ACTUAL	ACTUAL	ACTUAL	TOTAL
A	1	Fuel Cost of System Generation	\$ 74,992,301	\$ 65,717,824	\$ 73,293,028	\$ 70,415,016	\$ 87,128,507	\$ 89,708,430	\$ 461,255,106
	2	Fuel Cost of Power Sold	(1,105,818)	(1,159,871)	(1,312,152)	(2,612,318)	(5,495,100)	(6,606,107)	(18,291,367)
	3	Fuel Cost of Purchased Power	1,777,132	3,137,635	6,173,029	1,917,858	6,444,417	9,797,876	29,247,948
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	7,319,413	7,093,012	5,551,577	5,410,902	7,518,681	7,427,850	40,321,435
	4	Energy Cost of Economy Purchases	143,759	406,521	1,053,448	485,384	407,645	188,921	2,685,678
	5	Adjustments to Fuel Cost	(12,011,163)	1,119,402	1,152,738	1,147,328	1,142,435	1,139,918	(6,309,342)
	6	TOTAL FUEL & NET POWER TRANSACTIONS	71,115,625	76,314,523	85,911,668	76,764,171	97,146,585	101,656,887	508,909,459
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	2,640,090	2,661,152	2,818,044	3,239,130	2,981,766	3,450,388	17,790,571
	2	Non-Jurisdictional MWH Sales	14,426	18,358	26,409	25,344	19,970	25,961	130,469
	3	TOTAL SALES (Lines B1 + B2)	2,654,517	2,679,511	2,844,453	3,264,474	3,001,736	3,476,349	17,921,039
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.46%	99.31%	99.07%	99.22%	99.33%	99.25%	99.27%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	85,968,564	86,669,575	91,874,742	103,746,698	25,329,422	115,589,082	509,178,083
	2	True-Up Provision	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	77,026,561	(1,205,224)	71,000,441
	2a	Incentive Provision	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(1,295,850)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	84,547,365	85,248,376	90,453,543	102,325,499	102,140,008	114,167,883	578,882,674
	4	Fuel & Net Power Transactions (Line A6)	71,115,625	76,314,523	85,911,668	76,764,171	97,146,585	101,656,887	508,909,459
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	70,755,650	75,811,447	85,139,074	76,189,021	96,525,617	100,925,738	505,346,546
	6	Over/(Under) Recovery (Line 3 - Line 5)	13,791,715	9,436,929	5,314,469	26,136,477	5,614,392	13,242,145	73,536,127
	7	Interest Provision	(38,474)	(20,905)	(11,239)	9,273	(736)	(3,260)	(65,341)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	13,753,241	9,416,023	5,303,230	26,145,750	5,613,656	13,238,886	73,470,786
	9	Plus: Prior Period Balance	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)
	10	Plus: Cumulative True-Up Provision	1,205,224	2,410,448	3,615,672	4,820,896	(72,205,665)	(71,000,441)	(71,000,441)
	11	Subtotal Prior Period True-up	(34,792,690)	(33,587,466)	(32,382,242)	(31,177,018)	(108,203,579)	(106,998,355)	(106,998,355)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	(\$21,039,449)	(\$10,418,201)	(\$3,909,747)	\$23,441,227	(\$47,971,678)	(\$33,527,567)	(33,527,567)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of 2017 Actual/Estimated True-up
January 2020 - December 2020 (Filed 7/27/20, Revised 9/2/20)

			JUL	AUG	SEPT	OCT	NOV	DEC	12 MONTH
			EST MATED	EST MATED	ESTIMATED	ESTIMATED	ESTIMATED	ESTIMATED	PERIOD
A	1	Fuel Cost of System Generation	\$ 91,270,574	\$ 102,001,873	\$ 96,405,019	\$ 90,833,949	\$ 85,974,737	\$ 97,148,448	\$ 1,024,889,706
	2	Fuel Cost of Power Sold	(7,409,067)	(8,021,690)	(7,971,710)	(7,577,999)	(2,497,439)	(2,446,122)	(54,215,393)
	3	Fuel Cost of Purchased Power	8,533,384	4,575,768	3,696,906	4,358,593	1,085,538	174,484	51,672,621
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	8,407,595	8,411,122	7,949,571	7,091,011	8,225,712	9,032,312	89,438,758
	4	Energy Cost of Economy Purchases	177,886	113,649	178,038	128,590	91,292	125,383	3,500,516
	5	Adjustments to Fuel Cost	1,136,872	1,651,425	1,124,387	1,120,886	1,117,160	1,113,548	954,935
	6	TOTAL FUEL & NET POWER TRANSACTIONS	102,117,245	108,732,147	101,382,212	95,955,030	93,997,000	105,148,053	1,116,241,144
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	3,923,462	3,994,662	3,898,898	3,525,887	2,811,544	2,776,042	38,721,066
	2	Non-Jurisdictional MWH Sales	36,956	37,435	17,800	16,080	12,182	11,792	262,713
	3	TOTAL SALES (Lines B1 + B2)	3,960,418	4,032,097	3,916,698	3,541,967	2,823,725	2,787,834	38,983,778
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.07%	99.07%	99.55%	99.55%	99.57%	99.58%	99.33%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	131,162,478	133,542,731	130,341,300	117,871,449	93,990,725	92,803,906	1,208,890,671
	2	True-Up Provision	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	63,769,102
	2a	Incentive Provision	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(215,972)	(2,591,697)
	3	FUEL REVENUE APPLICABLE TO PERIOD	129,741,279	132,121,532	128,920,101	116,450,250	92,569,526	91,382,710	1,270,068,076
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	102,117,245	108,732,147	101,382,212	95,955,030	93,997,000	105,148,053	1,116,241,144
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	101,198,916	107,754,331	100,957,279	95,552,845	93,621,826	104,738,890	1,109,170,633
	6	Over/(Under) Recovery (Line 3 - Line 5)	28,542,363	24,367,201	27,962,822	20,897,406	(1,052,301)	(13,356,180)	160,897,438
	7	Interest Provision	(1,489)	724	2,914	4,965	5,854	5,375	(46,998)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	28,540,875	24,367,925	27,965,736	20,902,370	(1,046,446)	(13,350,805)	160,850,440
	9	Plus: Prior Period Balance	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)
	10	Plus: Cumulative True-Up Provision	(69,795,217)	(68,589,993)	(67,384,769)	(66,179,545)	(64,974,321)	(63,769,101)	(63,769,101)
	11	Subtotal Prior Period True-up	(105,793,131)	(104,587,907)	(103,382,683)	(102,177,459)	(100,972,235)	(99,767,015)	(99,767,015)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	(\$3,781,471)	\$21,791,678	\$50,962,638	\$73,070,232	\$73,229,010	\$61,083,424	61,083,424

Duke Energy Florida, LLC
Fuel Adjustment Clause
Fuel and Net Power Cost Variance Analysis
January 2020 - December 2020

(A)	(B)	(C)	(D)	(E)
Energy Source	MWH Variances	Heat Rate Variances	Price Variances	Total
1 Heavy Oil	0	0	0	0
2 Light Oil	1,937,834	1,802,014	38,717	3,778,565
3 Coal	30,723	2,171,141	(1,323,627)	878,237
4 Gas	9,173,776	20,094,214	15,526,447	44,794,438
5 Nuclear	0	0	0	0
6 Other Fuel	0	0	0	0
7 Total Generation	11,142,333	24,067,369	14,241,538	49,451,240
8 Firm Purchases	5,017,787	0	9,110,110	14,127,897
9 Economy Purchases	1,407,022	0	(158,751)	1,248,271
10 Schedule E Purchases	0	0	0	0
11 Qualifying Facilities	(5,081,623)	0	608,183	(4,473,440)
12 Total Purchases	1,343,186	0	9,559,543	10,902,728
13 Economy Sales	0	0	0	0
14 Other Power Sales	905	0	988,133	989,037
15 Supplemental Sales	(288,617)	0	(5,686,211)	(5,974,828)
16 Total Sales	(287,713)	0	(4,698,078)	(4,985,791)
17 Total Fuel and Net Power Cost Variance	12,197,806	24,067,369	19,103,002	55,368,177

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January 2020 - December 2020

Line No.	Description	Actual	Actual/Estimated Filing	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 40 & Sheet 3 of 3, Line 34	\$ 418,087,749	\$ 411,153,636	\$ 6,934,113
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 36 & Sheet 3 of 3, Line 30	411,177,543	410,776,553	400,989
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 44 & Sheet 3 of 3, Line 37	<u>(42,342)</u>	<u>(42,389)</u>	<u>46</u>
4	Sub-Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 45 & Sheet 3 of 3, Line 38	\$ 6,867,864	\$ 334,694	\$ 6,533,170
5	Prior Period True-up - January through December 2019 - Over/(Under) Recovery Sheet 2 of 3, Line 46 & Sheet 3 of 3, Line 39	1,050,728	1,050,730	-2
6	Prior Period True-up - January through December 2019 - (Refunded)/Collected Sheet 2 of 3, Line 47 & Sheet 3 of 3, Line 40	<u>(1,848,509)</u>	<u>(1,848,509)</u>	<u>0</u>
7	Actual True-Up Ending Balance Over/(Under) Recovery for the Period January through December 2020 Sheet 2 of 3, Line 49 & Sheet 3 of 3, Line 42	\$ 6,070,083	\$ (463,084)	\$ 6,533,167
8	Estimated True-Up Ending Balance for the Period Included in the Filing of Levelized Fuel Cost Factors January through December 2021 per Order No. PSC-2021-0024-FOF-EI (Sheet 3 of 3, Line 42)	(\$463,084)		
9	Total Over/(Under) Recovery for the Period January through December 2019 (Line 7 - Line 8)	<u>\$ 6,533,167</u>		

Duke Energy Florida, LLC
 Capacity Cost Recovery Clause
 Calculation of Actual True-Up
 January 2020 - December 2020

	JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	Total
1 Base Production Level Capacity Costs													
2 Orange Cogen (ORANGE CO)	5,880,980	5,893,358	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	70,646,032
3 Orlando Cogen Limited (ORLACOG)	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	71,080,259
4 Pasco County Resource Recovery (PASCOUNT)	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	25,772,880
5 Pinellas County Resource Recovery (PINCOUNT)	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	61,350,660
6 Polk Power Partners, L.P. (MULBERRY/ROYSER)	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	7,859,863	8,313,571	8,086,717	8,086,717	8,086,717	97,040,602
7 Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	0	0	0	0	0	0	0	0	0	0	0	0	0
8 US EcoGen	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Subtotal - Base Level Capacity Costs	27,151,347	27,163,725	27,157,536	27,157,536	27,157,536	27,157,536	27,157,536	26,930,682	27,384,390	27,157,536	27,157,536	27,157,536	325,890,433
10 Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
11 Base Level Jurisdictional Capacity Costs	25,219,529	25,231,026	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	25,014,564	25,435,991	25,225,277	25,225,277	25,225,277	302,703,330
12 Intermediate Production Level Capacity Costs													
13 Southern Franklin	4,016,449	5,550,785	2,815,069	2,816,679	1,738,090	4,096,953	5,413,842	6,559,806	7,304,380	2,851,285	2,833,088	3,689,267	49,685,693
14 Schedule H Capacity Sales	0	0	(32,469)	0	0	0	0	(32,125)	(5,587)	(61,457)	0	0	(131,637)
15 Subtotal - Intermediate Level Capacity Costs	4,016,449	5,550,785	2,782,600	2,816,679	1,738,090	4,096,953	5,413,842	6,527,681	7,298,793	2,789,828	2,833,088	3,689,267	49,554,055
16 Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
17 Intermediate Level Jurisdictional Capacity Costs	2,920,079	4,035,587	2,023,034	2,047,810	1,263,644	2,978,608	3,936,025	4,745,820	5,306,442	2,028,289	2,059,740	2,682,208	36,027,285
18 Peaking Production Level Capacity Costs													
19 Shady Hills	1,973,160	1,973,160	1,973,160	802,440	1,912,680	3,911,760	3,904,200	3,904,200	1,821,960	1,371,600	1,371,600	1,976,940	26,896,860
20 Vandolah	2,939,299	2,876,217	1,958,481	1,943,807	2,807,348	5,839,892	5,903,915	5,834,456	2,761,749	1,944,121	2,042,628	2,997,569	39,849,482
21 Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22 Subtotal - Peaking Level Capacity Costs	4,912,459	4,849,377	3,931,641	2,746,247	4,720,028	9,751,652	9,808,115	9,738,656	4,583,709	3,315,721	3,414,228	4,974,509	66,746,342
23 Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
24 Peaking Level Jurisdictional Capacity Costs	4,712,227	4,651,717	3,771,387	2,634,310	4,527,640	9,354,175	9,408,336	9,341,708	4,396,877	3,180,572	3,275,064	4,771,748	64,025,761
25 Other Capacity Costs													
26 Retail Wheeling	(10,726)	(9,947)	0	(17,012)	(2,126)	(837)	(8,413)	(36,277)	(9,642)	(2,514)	0	(18,317)	(115,810)
27 Ridge Generating Station L.P. Termination ¹	708,094	704,621	701,149	697,676	694,203	690,731	687,052	683,585	680,117	676,649	673,181	669,714	8,266,772
28 State Corporate Income Tax Change ²	-	-	(3,491,633)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(5,586,617)
29 SoBRA True-Up - Columbia	-	-	-	-	-	-	-	-	(133,589)	-	-	-	(133,589)
30 SoBRA True-Up - DeBary	-	-	-	-	-	-	-	-	(77,810)	-	-	-	(77,810)
31 SoBRA True-Up - Lake Placid	-	-	-	-	-	-	-	-	(213,688)	-	-	-	(213,688)
32 SoBRA True-Up - Trenton	-	-	-	-	-	-	-	-	(597,927)	-	-	-	(597,927)
33 Total Other Capacity Costs	697,369	694,674	(2,790,484)	447,888	459,301	457,118	445,863	414,532	(585,315)	441,359	440,405	418,621	1,541,331
34 Total Capacity Costs (Line 11+17+24+33)	33,549,203	34,613,004	28,229,214	30,355,285	31,475,861	38,015,180	39,015,502	39,516,624	34,553,996	30,875,497	31,000,487	33,097,854	404,297,707
35 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
36 Total Recoverable Capacity & ISFSI Costs (line 34+35)	34,122,523	35,186,324	28,802,534	30,928,605	32,049,180	38,588,499	39,588,821	40,089,944	35,127,315	31,448,817	31,573,807	33,671,174	411,177,543
37 Capacity Revenues:													
38 Capacity Cost Recovery Revenues (net of tax)	27,694,435	28,661,108	29,875,620	34,161,020	32,020,716	36,912,727	42,078,331	41,023,530	40,841,915	36,549,710	35,044,527	31,375,602	416,239,240
39 Prior Period True-Up Provision Over/(Under) Recovery	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	1,848,509
40 Current Period CCR Revenues (net of tax)	27,848,477	28,815,151	30,029,662	34,315,063	32,174,759	37,066,769	42,232,373	41,177,573	40,995,957	36,703,752	35,198,569	31,529,645	418,087,749
41													
42 True-Up Provision													
43 True-Up Provision - Over/(Under) Recov (Line 40-36)	(6,274,046)	(6,371,173)	1,227,128	3,386,457	125,578	(1,521,729)	2,643,551	1,087,629	5,868,642	5,254,935	3,624,762	(2,141,528)	6,910,206
44 Interest Provision for the Month	(2,912)	(11,495)	(17,867)	(8,783)	(459)	(680)	(810)	(639)	(245)	164	663	722	(42,342)
45 Current Cycle Balance - Over/(Under)	(6,276,958)	(12,659,626)	(11,450,365)	(8,072,691)	(7,947,573)	(9,469,982)	(6,827,241)	(5,740,251)	128,146	5,383,245	9,008,670	6,867,864	6,867,864
46 Prior Period Balance - Over/(Under) Recovered	1,050,728	896,686	742,643	588,601	434,559	280,516	126,474	(27,569)	(181,611)	(335,653)	(489,696)	(643,738)	1,050,728
47 Prior Period Cumulative True-Up Collected/(Refunded)	(154,042)	(154,042)	(154,042)	(154,042)	(154,042)	(154,042)	(154,042)	(154,042)	(154,042)	(154,042)	(154,042)	(154,042)	(1,848,509)
48 Prior Period True-up Balance - Over/(Under)	896,686	742,643	588,601	434,559	280,516	126,474	(27,569)	(181,611)	(335,653)	(489,696)	(643,738)	(797,781)	(797,781)
49 Net Capacity True-up Over/(Under) (Line 45+48)	(5,380,272)	(11,916,982)	(10,861,764)	(7,638,133)	(7,667,056)	(9,343,508)	(6,854,809)	(5,921,862)	(207,507)	4,893,549	8,364,932	6,070,083	6,070,083

¹ Approved in Commission Order No. PSC-2018-0532-PAA-EQ.

² Third Implementation Stipulation approved in Order No. PSC-2021-0024-FOF-EI.

³ As set forth in DEF's 2017 Settlement approved in Commission Order No. PSC-2017-0451-AS-EU.
 Approved in Commission Order No. PSC-2021-0024-FOF-EI.

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Calculation of Actual/Estimated True-Up
January 2020 - December 2020 (Filed 7/27/20)

	JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	Total
1 Base Production Level Capacity Costs													
2 Orange Cogen (ORANGE CO)	5,880,980	5,893,358	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	70,646,031
3 Orlando Cogen Limited (ORLACOGL)	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	71,080,258
4 Pasco County Resource Recovery (PASCOUNT)	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	25,772,880
5 Pinellas County Resource Recovery (PINCOUNT)	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	61,350,660
6 Polk Power Partners, L.P. (MULBERRY/ROYSER)	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	97,040,600
7 Subtotal - Base Level Capacity Costs	27,151,347	27,163,725	27,157,536	27,157,536	27,157,536	27,157,536	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	325,890,428
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	25,219,529	25,231,025	25,225,276	25,225,276	25,225,276	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	302,703,319
10 Intermediate Production Level Capacity Costs													
11 Southern Franklin	4,016,449	5,550,785	2,815,069	2,816,679	1,738,090	4,096,953	6,653,118	6,653,118	4,939,686	2,940,682	2,940,682	3,797,398	48,958,709
12 Schedule H Capacity Sales	-	-	(32,469)	-	-	-	-	-	-	-	-	-	(32,469)
13 Subtotal - Intermediate Level Capacity Costs	4,016,449	5,550,785	2,782,600	2,816,679	1,738,090	4,096,953	6,653,118	6,653,118	4,939,686	2,940,682	2,940,682	3,797,398	48,926,240
14 Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
15 Intermediate Level Jurisdictional Capacity Costs	2,920,079	4,035,587	2,023,034	2,047,810	1,263,645	2,978,608	4,837,016	4,837,016	3,591,300	2,137,964	2,137,964	2,760,822	35,570,845
16 Peaking Production Level Capacity Costs													
17 Shady Hills	1,973,160	1,973,160	1,973,160	802,440	1,912,680	3,911,760	3,889,124	3,889,124	1,814,925	1,366,449	1,366,449	1,971,891	26,844,323
18 Vandolah (NSG)	2,939,299	2,876,217	1,958,481	1,943,807	2,807,348	5,839,892	5,617,529	5,572,423	2,666,444	1,963,912	2,009,019	2,826,948	39,021,320
19 Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20 Subtotal - Peaking Level Capacity Costs	4,912,459	4,849,377	3,931,641	2,746,247	4,720,028	9,751,652	9,506,654	9,461,547	4,481,369	3,330,362	3,375,468	4,798,839	65,865,643
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	4,712,227	4,651,717	3,771,387	2,634,310	4,527,640	9,354,175	9,119,162	9,075,895	4,298,708	3,194,616	3,237,884	4,603,238	63,180,959
23 Other Capacity Costs													
24 Retail Wheeling	(10,726)	(9,947)	-	(17,012)	(2,126)	(837)	(40,983)	(45,545)	(38,603)	(15,942)	(15,280)	(41,558)	(238,559)
25 Ridge Generating Station L.P. Termination ¹	708,094	704,621	701,149	697,676	694,203	690,731	687,051	683,583	680,115	676,648	673,180	669,712	8,266,764
26 State Corporate Income Tax Change ²	-	-	(3,491,633)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(5,586,614)
27 Total Other Capacity Costs	697,369	694,674	(2,790,484)	447,888	459,301	457,118	413,292	405,262	408,737	427,930	425,124	395,379	2,441,591
28 Total Capacity Costs (line 9+15+22+27)	33,549,204	34,613,003	28,229,213	30,355,284	31,475,861	38,015,179	39,594,748	39,543,450	33,524,022	30,985,786	31,026,249	32,984,716	403,896,715
29 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
30 Total Recoverable Capacity & ISFSI Costs (line 28+29)	34,122,523	35,186,323	28,802,534	30,928,605	32,049,181	38,588,498	40,168,068	40,116,770	34,097,342	31,559,106	31,599,569	33,558,036	410,776,553
31 Capacity Revenues													
32 Capacity Cost Recovery Revenues (net of tax)	27,694,435	28,661,108	29,875,620	34,161,020	32,020,716	36,912,727	41,235,583	41,983,900	40,977,417	37,057,076	29,549,322	29,176,204	409,305,128
33 Prior Period True-Up Provision Over/(Under) Recovery	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	1,848,508
34 Current Period Revenues (net of tax)	27,848,477	28,815,151	30,029,662	34,315,063	32,174,759	37,066,769	41,389,626	42,137,943	41,131,459	37,211,119	29,703,365	29,330,246	411,153,636
35 True-Up Provision													
36 True-Up Provision - Over/(Under) Recov (Line 34-30)	(6,274,046)	(6,371,172)	1,227,128	3,386,458	125,578	(1,521,729)	1,221,558	2,021,173	7,034,117	5,652,012	(1,896,204)	(4,227,790)	377,083
37 Interest Provision for the Month	(2,912)	(11,495)	(17,867)	(8,783)	(459)	(680)	(331)	(256)	19	239	157	(19)	(42,389)
38 Current Cycle Balance - Over/(Under)	(6,276,958)	(12,659,626)	(11,450,367)	(8,072,693)	(7,947,575)	(9,469,984)	(8,248,757)	(6,227,840)	806,295	6,458,546	4,562,499	334,694	334,694
39 Prior Period Balance - Over/(Under) Recovered	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730
40 Prior Period Cumulative True-Up Collected/(Refunded)	(154,042)	(308,085)	(462,127)	(616,170)	(770,212)	(924,255)	(1,078,297)	(1,232,339)	(1,386,382)	(1,540,424)	(1,694,467)	(1,848,509)	(1,848,509)
41 Prior Period True-up Balance - Over/(Under)	896,686	742,643	588,601	434,559	280,516	126,474	(27,567)	(181,609)	(335,651)	(489,694)	(643,736)	(797,779)	(797,779)
42 Net Capacity True-up Over/(Under) (Line 38+41)	(\$5,380,272)	(\$11,916,982)	(\$10,861,764)	(\$7,638,133)	(\$7,667,056)	(\$9,343,508)	(\$8,276,324)	(\$6,409,449)	\$470,644	\$5,968,852	\$3,918,763	(\$463,084)	(\$463,084)

¹ Approved in Commission Order No. PSC-2018-0532-PAA-EQ.

² Third Implementation Stipulation approved in Order No. PSC-2021-0024-FOF-EI.

³ As set forth in DEF's 2017 Settlement approved in Commission Order No. PSC-2017-0451-AS-EU.

\$					MWH					CENTS/KWH				
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	
1 FUEL COST OF SYSTEM NET GENERATION (SCH A3)	96,045,352	97,148,448	(1,103,096)	(1.1)	2,956,329	2,937,259	19,070	0.7		3.2488	3.3075	(0.0587)	(1.8)	
2 COAL CAR SALE	0	0	0	0.0	0	0	0	0.0		0.0000	0.0000	0.0000	0.0	
3 ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	4,072,496	1,113,548	2,958,948	265.7	0	0	0	0.0		0.0000	0.0000	0.0000	0.0	
4 TOTAL COST OF GENERATED POWER	100,117,848	98,261,996	1,855,852	1.9	2,956,329	2,937,259	19,070	0.7		3.3866	3.3454	0.0412	1.2	
5 ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	5,614,657	174,484	5,440,173	3,117.9	104,596	3,489	101,107	2,897.9		5.3679	5.0010	0.3669	7.3	
6 ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	-	0	0	0.0	0	0	0	0.0		0.0000	0.0000	0.0000	0.0	
7 ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	517,065	125,383	391,682	312.4	17,719	3,278	14,440	440.5		2.9182	3.8249	(0.9067)	(23.7)	
8 PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	8,161,873	9,032,312	(870,439)	(9.6)	214,069	251,175	(37,107)	(14.8)		3.8127	3.5960	0.2167	6.0	
9 TOTAL COST OF PURCHASED POWER	14,293,594	9,332,179	4,961,415	53.2	336,383	257,942	78,441	30.4		4.2492	3.6179	0.6313	17.5	
10 TOTAL AVAILABLE MWH					3,292,712	3,195,201	97,511	3.1						
11 FUEL COST OF OTHER POWER SALES (SCH A6)	(169,978)	(624,551)	454,573	(72.8)	(6,780)	(21,425)	14,645	(68.4)		2.5070	2.9151	(0.4081)	(14.0)	
11a GAIN ON OTHER POWER SALES - 100% (SCH A6)	(69,741)	(158,368)	88,627	(56.0)	(6,780)	(21,425)	14,645	(68.4)		1.0286	0.7392	0.2894	39.2	
11b GAIN ON TOTAL POWER SALES - 20% (SCH A6)	0	0	0	0.0	0	0	0	0.0		0.0000	0.0000	0.0000	0.0	
12 FUEL COST OF STRATIFIED SALES	(6,250,010)	(1,663,203)	(4,586,808)	275.8	(206,618)	(76,552)	(130,066)	169.9		3.0249	2.1726	0.8523	39.2	
13 TOTAL FUEL COST AND GAINS ON POWER SALES	(6,489,729)	(2,446,122)	(4,043,608)	165.3	(213,398)	(97,977)	(115,421)	117.8		3.0411	2.4966	0.5445	21.8	
14 NET INADVERTENT AND WHEELED INTERCHANGE					15,481	0	15,481							
15 TOTAL FUEL AND NET POWER TRANSACTIONS	107,921,713	105,148,053	2,773,660	2.6	3,094,795	3,097,224	(2,429)	(0.1)		3.4872	3.3949	0.0923	2.7	
16 NET UNBILLED	2,722,981	3,612,855	(889,874)	(24.6)	(78,085)	(106,420)	28,335	(26.6)		0.0936	0.1296	(0.0360)	(27.8)	
17 COMPANY USE	165,683	602,434	(436,751)	(72.5)	(4,751)	(17,745)	12,994	(73.2)		0.0057	0.0216	(0.0159)	(73.6)	
18 T & D LOSSES	3,581,983	6,288,228	(2,706,245)	(43.0)	(102,718)	(185,225)	82,507	(44.5)		0.1231	0.2256	(0.1025)	(45.4)	
19 ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	107,921,713	105,148,053	2,773,660	2.6	2,909,241	2,787,834	121,407	4.4		3.7096	3.7717	(0.0621)	(1.7)	
20 WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(474,856)	(441,622)	(33,234)	7.5	(12,812)	(11,792)	(1,021)	8.7		3.7063	3.7453	(0.0390)	(1.0)	
21 JURISDICTIONAL KWH SALES	107,446,857	104,706,431	2,740,426	2.6	2,896,428	2,776,042	120,386	4.3		3.7096	3.7718	(0.0622)	(1.7)	
22 JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00112	107,480,166	104,738,890	2,741,276	2.6	2,896,428	2,776,042	120,386	4.3		3.7108	3.7730	(0.0622)	(1.7)	
23 PRIOR PERIOD TRUE-UP	1,205,224	1,205,224	(0)	0.0	2,896,428	2,776,042	120,386	4.3		0.0416	0.0434	(0.0018)	(4.2)	
24 TOTAL JURISDICTIONAL FUEL COST	108,685,390	105,944,114	2,741,276	2.6	2,896,428	2,776,042	120,386	4.3		3.7524	3.8164	(0.0640)	(1.7)	
25 REVENUE TAX FACTOR										1.00072	1.00072	0.0000	0.0	
26 FUEL COST ADJUSTED FOR TAXES										3.7551	3.8191	(0.0640)	(1.7)	
27 GPIF	215,975	215,972			2,896,428	2,776,042				0.0075	0.0078	(0.0003)	(3.9)	
28 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH										3.763	3.827	(0.064)	(1.7)	

*Line 15a. MWH Data for Informational Purposes Only

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2020

SCHEDULE A1
PAGE 2 OF 2

Docket No. 20210001-EI
Witness: Dean
Exhibit No. (GPD-3T)
Schedule A1-2
Sheet 2 of 9

\$					MWH				CENTS/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,074,340,946	1,024,889,706	49,451,240	4.8	40,353,901	40,030,421	323,480	0.8	2.6623	2.5603	0.1020	4.0
2 COAL CAR SALE	20,648	0	20,648	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3 ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	3,909,720	954,935	2,954,785	309.4	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4 TOTAL COST OF GENERATED POWER	1,078,271,315	1,025,844,641	52,426,673	5.1	40,353,901	40,030,421	323,480	0.8	2.6720	2.5627	0.1093	4.3
5 ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	65,800,518	51,672,621	14,127,897	27.3	1,789,013	1,630,664	158,349	9.7	3.6780	3.1688	0.5092	16.1
6 ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
7 ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	4,748,788	3,500,516	1,248,271	35.7	154,736	110,373	44,364	40.2	3.0690	3.1715	(0.1025)	(3.2)
8 PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	84,965,318	89,438,758	(4,473,440)	(5.0)	2,422,304	2,568,222	(145,918)	(5.7)	3.5076	3.4825	0.0251	0.7
9 TOTAL COST OF PURCHASED POWER	155,514,624	144,611,896	10,902,728	7.5	4,366,053	4,309,258	56,795	1.3	3.5619	3.3558	0.2061	6.1
10 TOTAL AVAILABLE MWH					44,719,955	44,339,679	380,275	0.9				
11 FUEL COST OF OTHER POWER SALES (SCH A6)	(2,825,626)	(3,909,810)	1,084,184	(27.7)	(132,534)	(132,558)	24	(0.0)	2.1320	2.9495	(0.8175)	(27.7)
11a GAIN ON OTHER POWER SALES - 100% (SCH A6)	(1,223,709)	(1,128,563)	(95,146)	8.4	(132,534)	(132,558)	24	(0.0)	0.9233	0.8514	0.0719	8.4
11b GAIN ON TOTAL POWER SALES - 20% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
12 FUEL COST OF STRATIFIED SALES	(55,151,849)	(49,177,021)	(5,974,828)	12.2	(2,642,019)	(2,626,604)	(15,415)	0.6	2.0875	1.8723	0.2152	11.5
13 TOTAL FUEL COST AND GAINS ON POWER SALES	(59,201,184)	(54,215,393)	(4,985,791)	9.2	(2,774,553)	(2,759,161)	(15,392)	0.6	2.1337	1.9649	0.1688	8.6
14 NET INADVERTENT AND WHEELED INTERCHANGE					236,508	110,445	126,063					
15 TOTAL FUEL AND NET POWER TRANSACTIONS	1,174,584,754	1,116,241,144	58,343,610	5.2	42,181,910	41,690,963	490,947	1.2	2.7846	2.6774	0.1072	4.0
16 NET UNBILLED	3,232,304	1,753,587	1,478,717	84.3	(240,833)	(67,995)	(172,837)	254.2	0.0082	0.0045	0.0037	82.2
17 COMPANY USE	2,971,792	4,520,732	(1,548,940)	(34.3)	(109,876)	(165,751)	55,874	(33.7)	0.0075	0.0116	(0.0041)	(35.3)
18 T & D LOSSES	63,863,953	66,234,713	(2,370,760)	(3.6)	(2,346,351)	(2,473,438)	127,087	(5.1)	0.1617	0.1699	(0.0082)	(4.8)
19 ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	1,174,584,754	1,116,241,144	58,343,610	5.2	39,484,849	38,983,778	501,071	1.3	2.9748	2.8633	0.1115	3.9
20 WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(7,176,203)	(7,416,368)	240,165	(3.2)	(244,769)	(262,713)	17,944	(6.8)	2.9318	2.8230	0.1088	3.9
21 JURISDICTIONAL KWH SALES	1,167,408,551	1,108,824,776	58,583,775	5.3	39,240,080	38,721,066	519,015	1.3	2.9750	2.8636	0.1114	3.9
22 JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00112	1,167,772,570	1,109,170,633	58,601,936	5.3	39,240,080	38,721,066	519,015	1.3	2.9760	2.8645	0.1115	3.9
23 PRIOR PERIOD TRUE-UP	(63,769,101)	(63,769,099)	(2)	0.0	39,240,080	38,721,066	519,015	1.3	(0.1625)	(0.1647)	0.0022	(1.3)
24 TOTAL JURISDICTIONAL FUEL COST	1,104,003,469	1,045,401,534	58,601,934	5.6	39,240,080	38,721,066	519,015	1.3	2.8135	2.6998	0.1137	4.2
25 REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
26 FUEL COST ADJUSTED FOR TAXES									2.8155	2.7017	0.1138	4.2
27 GPIF	2,591,697	2,591,697			39,240,080	38,721,066			0.0066	0.0067	(0.0001)	101.5
28 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									2.822	2.708	0.114	4.2

*Line 15a. MWH Data for Informational Purposes Only

CURRENT MONTH					YEAR TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
A . FUEL COSTS AND NET POWER TRANSACTIONS								
1. FUEL COST OF SYSTEM NET GENERATION	\$96,045,352	97,148,448	(\$1,103,096)	(1.1)	\$1,074,340,946	\$1,024,889,706	\$49,451,240	4.8
1a. COAL CAR SALE	-	0	0	0.0	20,648	0	20,648	0.0
2. FUEL COST OF POWER SOLD	(169,978)	(624,551)	454,573	(72.8)	(2,825,626)	(3,909,810)	1,084,184	(27.7)
2a. GAIN ON POWER SALES	(69,741)	(158,368)	88,627	(56.0)	(1,223,709)	(1,128,563)	(95,146)	8.4
3. FUEL COST OF PURCHASED POWER	5,614,657	174,484	5,440,173	3,117.9	65,800,518	51,672,621	14,127,897	27.3
3a. ENERGY PAYMENTS TO QUALIFYING FACILITIES	8,161,873	9,032,312	(870,439)	(9.6)	84,965,318	89,438,758	(4,473,440)	(5.0)
4. ENERGY COST OF ECONOMY PURCHASES	517,065	125,383	391,682	312.4	4,748,788	3,500,516	1,248,271	35.7
5. TOTAL FUEL & NET POWER TRANSACTIONS	110,099,228	105,697,708	4,401,520	4.2	1,225,826,884	1,164,463,229	61,363,654	5.3
6. ADJUSTMENTS TO FUEL COST:								
6a. FUEL COST OF STRATIFIED SALES	(6,250,010)	(1,663,203)	(4,586,808)	275.8	(55,151,849)	(49,177,021)	(5,974,828)	12.2
6b. OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	4,072,496	1,113,548	2,958,948	265.7	3,909,720	954,935	2,954,785	309.4
6c. OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR TRNS	\$107,921,713	\$105,148,053	\$2,773,660	2.6	\$1,174,584,754	\$1,116,241,144	\$58,343,610	5.2

FOOTNOTE: DETAIL OF LINE 6b ABOVE

N/A - Not used	\$0	\$0	\$0	\$0	\$0	\$0	\$0
N/A - Not used	0	0	0	0	0	0	0
UNIVERSITY OF FLORIDA STEAM REVENUE ALLOCATION (Wholesale Portion)	440	0	440	7,460	0	7,460	
WHOLESALE ALLOCATION ADJUSTMENT	0	0	0	517,236	0	517,236	
TANK BOTTOM ADJUSTMENT	25,765	0	25,765	25,765	0	25,765	
AERIAL SURVEY ADJUSTMENT (Coal Pile)	2,932,514	0	2,932,514	2,932,514	0	2,932,514	
FPD AGREEMENT TERMINATION	1,113,777	0	1,113,777	13,626,585	0	13,626,585	
RAIL CAR SALE PROCEEDS	0	0	0	0	0	0	
CITRUS SETTLEMENT FUEL GIVEBACK	0	0	0	(13,309,268)	0	(13,309,268)	
NET METER SETTLEMENT	0	0	0	125,131	0	125,131	
2019 ADJUSTMENT: GAIN ON TOTAL POWER SALES - 20% (SCH A6) **	0	0	0	(15,703)	0	(15,703)	
Derivative Collateral Interest	0	0	0	0	0	0	
SUBTOTAL LINE 6b SHOWN ABOVE	\$4,072,496	\$0	\$4,072,496	\$3,909,720	\$0	\$3,909,720	

** Adjustment to correct 2019 customer gain on non-separate wholesale sales.

B. KWH SALES								
1. JURISDICTIONAL SALES	2,896,428,219	2,776,042,226	120,385,993	4.3	39,240,079,165	38,721,065,605	519,013,560	1.3
2. NON JURISDICTIONAL (WHOLESALE) SALES	12,812,247	11,791,500	1,020,747	8.7	244,768,746	262,712,827	(17,944,081)	(6.8)
3. TOTAL SALES	2,909,240,466	2,787,833,726	121,406,740	4.4	39,484,847,911	38,983,778,432	501,069,479	1.3
4. JURISDICTIONAL SALES % OF TOTAL SALES	99.56	99.58	(0.02)	(0.0)	99.38	99.33	0.05	0.1

DUKE ENERGY FLORIDA, LLC
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2020

SCHEDULE A2
PAGE 2 OF 2

Docket No.
Witness:
Exhibit No.
Schedule

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CURRENT MONTH						YEAR TO DATE			
						ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
						ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
C.	TRUE UP CALCULATION								
1.	JURISDICTIONAL FUEL REVENUE	\$94,186,011	\$92,803,906	\$1,382,105	1.5	\$1,227,999,849	\$1,208,890,671	\$19,109,178	1.6
2.	ADJUSTMENTS:	0	0	0	0.0	0	0	0	0.0
2a.	TRUE UP PROVISION	(1,205,224)	(1,205,224)	0	0.0	63,769,101	63,769,099	2	0.0
2b.	INCENTIVE PROVISION	(215,975)	(215,972)	(3)	0.0	(2,591,697)	(2,591,697)	0	0.0
3.	TOTAL JURISDICTIONAL FUEL REVENUE	92,764,813	91,382,710	1,382,103	1.5	1,289,177,253	1,270,068,073	19,109,180	1.5
4.	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	107,921,713	105,148,053	2,773,660	2.6	1,174,584,754	1,116,241,144	58,343,610	5.2
5.	JURISDICTIONAL SALES % OF TOT SALES (LINE B4)	99.56	99.58	(0.02)	(0.0)	99.38	99.33	0.05	0.1
6.	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE C4 * LINE C5 * 1.00112 LOSS MULTIPLIER)	107,480,166	104,738,890	2,741,276	2.6	1,167,772,570	1,109,170,633	58,601,936	5.3
7.	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE C3 - C6)	(14,715,353)	(13,356,180)	(1,359,173)	10.2	121,404,683	160,897,440	(39,492,757)	(24.6)
8.	INTEREST PROVISION FOR THE MONTH (LINE D10)	2,833	5,375	(2,542)	(47.3)	(58,082)	(46,998)	(11,084)	23.6
9.	TRUE UP & INTEREST PROVISION BEG OF MONTH/PERIOD	35,086,883	73,229,011	(38,142,128)	(52.1)	(35,997,914)	(35,997,914)	(0)	0.0
10.	TRUE UP COLLECTED (REFUNDED)	1,205,224	1,205,224	(0)	0.0	(63,769,101)	(63,769,099)	(2)	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES C7 + C8 + C9 + C10)	21,579,587	61,083,430	(39,503,843)	(64.7)	21,579,587	61,083,430	(39,503,843)	(64.7)
12.	OTHER:	0				0		0	
13.	END OF PERIOD TOTAL NET TRUE UP (LINES C11 + C12)	\$21,579,587	61,083,430	(39,503,843)	(64.7)	\$21,579,587	61,083,430	(39,503,843)	(64.7)
D.	INTEREST PROVISION								
1.	BEGINNING TRUE UP (LINE C9)	\$35,086,883	N/A	--	--				
2.	ENDING TRUE UP (LINES C7 + C9 + C10 + C12)	21,576,753	N/A	--	--				
3.	TOTAL OF BEGINNING & ENDING TRUE UP	56,663,636	N/A	--	--				
4.	AVERAGE TRUE UP (50% OF LINE D3)	28,331,818	N/A	--	--				
5.	INTEREST RATE - FIRST DAY OF REPORTING MONTH	0.140	N/A	--	--				
6.	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	0.100	N/A	--	--				
7.	TOTAL (LINE D5 + LINE D6)	0.240	N/A						
8.	AVERAGE INTEREST RATE (50% OF LINE D7)	0.120	N/A	--	--				
9.	MONTHLY AVERAGE INTEREST RATE (LINE D8/12)	0.010	N/A	--	--				
10.	INTEREST PROVISION (LINE D4 * LINE D9)	\$2,833	N/A	--	--				

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No. 20210001-EI
Witness: Dean
Exhibit No. (GPD-3T)
Schedule: A3-1
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FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION (\$)				
1 - HEAVY OIL	0	0	0	0.0 %
2 - LIGHT OIL	14,118,488	10,339,922	3,778,566	36.5 %
3 - COAL	128,688,321	127,810,084	878,237	0.7 %
4 - GAS	931,534,138	886,739,700	44,794,438	5.1 %
5 - NUCLEAR	0	0	0	0.0 %
6	0	0	0	0.0 %
7	0	0	0	0.0 %
8 - TOTAL (\$)	1,074,340,946	1,024,889,706	49,451,240	4.8 %
SYSTEM NET GENERATION (MWH)				
9 - HEAVY OIL	0	0	0	0.0 %
10 - LIGHT OIL	33,060	27,842	5,218	18.7 %
11 - COAL	3,287,271	3,286,481	790	0.0 %
12 - GAS	36,327,454	35,955,476	371,978	1.0 %
13 - NUCLEAR	0	0	0	0.0 %
14 - SOLAR	706,116	760,622	(54,506)	(7.2 %)
15	0	0	0	0.0 %
16 - TOTAL (MWH)	40,353,901	40,030,421	323,480	0.8 %
UNITS OF FUEL BURNED				
17 - HEAVY OIL (BBL)	0	0	0	0.0 %
18 - LIGHT OIL (BBL)	117,843	88,104	29,739	33.8 %
19 - COAL (TON)	1,562,463	1,459,784	102,679	7.0 %
20 - GAS (MCF)	269,892,525	264,606,132	5,286,393	2.0 %
21 - NUCLEAR (MMBTU)	0	0	0	0.0 %
22	0	0	0	0.0 %
23	0	0	0	0.0 %
BTUS BURNED (MILLION BTU)				
24 - HEAVY OIL	0	0	0	0.0 %
25 - LIGHT OIL	633,568	465,281	168,287	36.2 %
26 - COAL	35,171,675	34,576,013	595,662	1.7 %
27 - GAS	276,672,797	267,832,634	8,840,163	3.3 %
28 - NUCLEAR	0	0	0	0.0 %
29	0	0	0	0.0 %
30	0	0	0	0.0 %
31 - TOTAL (MILLION BTU)	312,478,040	302,873,928	9,604,112	3.2 %

A-3 Generating System Comparative Data Report

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FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATION MIX (% MWH)				
32 - HEAVY OIL	0.0	0.00	0.0	0.0 %
33 - LIGHT OIL	0.1	0.07	0.0	17.8 %
34 - COAL	8.1	8.21	(0.1)	(0.8 %)
35 - GAS	90.0	89.82	0.2	0.2 %
36 - NUCLEAR	0.0	0.00	0.0	0.0 %
37 - SOLAR	1.7	1.90	(0.15)	(7.9 %)
38	0	0	0	0
39 - TOTAL (% MWH)	100	100	0.0	0.0 %
FUEL COST PER UNIT (\$)				
40 - HEAVY OIL (\$/BBL)	0.00	0.00	0.00	0.0 %
41 - LIGHT OIL (\$/BBL)	119.81	117.36	2.45	2.1 %
42 - COAL (\$/TON)	82.36	87.55	(5.19)	(5.9 %)
43 - GAS (\$/MCF)	3.45	3.35	0.10	3.0 %
44 - NUCLEAR (\$/MBTU)	0.00	0.00	0.00	0.0 %
45	0.00	0.00	0.00	0.0 %
46	0.00	0.00	0.00	0.0 %
FUEL COST PER MILLION BTU (\$/MILLION BTU)				
47 - HEAVY OIL	0.00	0.00	0.00	0.0 %
48 - LIGHT OIL	22.28	22.22	0.06	0.3 %
49 - COAL	3.66	3.70	(0.04)	(1.0 %)
50 - GAS	3.37	3.31	0.06	1.7 %
51 - NUCLEAR	0.00	0.00	0.00	0.0 %
52	0.00	0.00	0.00	0.0 %
53	0.00	0.00	0.00	0.0 %
54 - SYSTEM (\$/MBTU)	3.44	3.38	0.05	1.6 %
BTU BURNED PER KWH (BTU/KWH)				
55 - HEAVY OIL	0	0	0	0.0 %
56 - LIGHT OIL	19,164	16,711	2,453	14.7 %
57 - COAL	10,699	10,521	179	1.7 %
58 - GAS	7,616	7,449	167	2.2 %
59 - NUCLEAR	0	0	0	0.0 %
60	0	0	0	0.0 %
61	0	0	0	0.0 %
62 - SYSTEM (BTU/KWH)	7,743	7,566	177	2.3 %

A-3 Generating System Comparative Data Report

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FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)				
63 - HEAVY OIL	0.00	0.00	0.00	0.0 %
64 - LIGHT OIL	42.71	37.14	5.57	15.0 %
65 - COAL	3.91	3.89	0.03	0.7 %
66 - GAS	2.56	2.47	0.10	4.0 %
67 - NUCLEAR	0.00	0.00	0.00	0.0 %
68	0.00	0.00	0.00	0.0 %
69	0.00	0.00	0.00	0.0 %
70 - SYSTEM (CENTS/KWH)	2.66	2.56	0.10	4.0 %

(1)	(2)	(3)	(4)	(5)	(6a)	(6b)	(7)	(8)	(9)
Sold To	Type & Schedule	Total KWH Sold (000)	KWH Wheeled from Other Systems (000)	KWH from Own Generation (000)	Fuel Cost C/KWH	Total Cost C/KWH	Fuel Adj Total \$	Total Cost \$	Gain on Sales \$
ESTIMATED		21,425		21,425	2.915	3.654	624,551.00	782,919.00	158,368.00
ACTUAL									
Reedy Creek Improvement District	CR-1	3,320		3,320	1.544	2.012	51,251.60	66,813.10	15,561.50
Southern Company Services, Inc.	EEI	3,100		3,100	3.513	3.945	108,908.16	122,296.08	13,387.92
Tampa Electric Company	CR-1	300		300	2.508	7.013	7,524.00	21,037.76	13,513.76
The Energy Authority	EEI	60		60	3.824	4.054	2,294.21	2,432.26	138.05
Adjustments									
PJM Settlements								2.98	2.98
Tampa Electric Company								27,136.83	27,136.83
Subtotal - Gain on Other Power Sales		6,780	0	6,780	2.507	3.536	169,977.97	239,719.01	69,741.04
CURRENT MONTH TOTAL		6,780		6,780	2.507	3.536	169,977.97	239,719.01	69,741.04
DIFFERENCE		(14,645)		(14,645)	(0.408)	(0.119)	(454,573.03)	(543,199.99)	(88,626.96)
DIFFERENCE %		(68)		(68)	(13.997)	(3.245)	(72.78)	(69.38)	(55.96)
CUMULATIVE ACTUAL		132,534		132,534	2.132	3.055	2,825,625.99	4,049,334.98	1,223,708.99
CUMULATIVE ESTIMATED		132,559		132,559	2.949	3.801	3,909,810.00	5,038,372.00	1,128,563.00
DIFFERENCE		(25)		(25)	(0.817)	(0.746)	(1,084,184.01)	(989,037.02)	95,145.99
DIFFERENCE %		(0)		(0)	(27.716)	(19.615)	(27.73)	(19.63)	8.43

Counterparty	Type	MW	Start Date - End Date	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
1 Orange Cogen (ORANGE CO)	QF	74.00	7/1/95 - 12/31/24	5,880,980	5,893,358	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	70,646,032
2 Orlando Cogen Limited (ORLACOGL)	QF	79.20	9/1/93 - 12/31/23	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	71,080,259
3 Pasco County Resource Recovery (PASCOUNT)	QF	23.00	1/1/95 - 12/31/24	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	25,772,880
4 Pinellas County Resource Recovery (PINCOUNT)	QF	54.75	1/1/95 - 12/31/24	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	61,350,660
5 Polk Power Partners, L.P. (MULBERRY)	QF	115.00	8/1/94 - 8/8/24	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	7,859,863	8,313,571	8,086,717	8,086,717	8,086,717	97,040,602
6 Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	QF	39.60	8/1/94 - 1/31/19	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Southern purchase - Franklin	Other	425	6/1/16 - 5/31/21	4,016,449	5,550,785	2,815,069	2,816,679	1,738,090	4,096,953	5,413,842	6,559,806	7,304,380	2,851,285	2,833,088	3,689,267	49,685,693
8 Retail Wheeling				(10,726)	(9,947)	0	(17,012)	(2,126)	(837)	(8,413)	(36,277)	(9,642)	(2,514)	0	(18,317)	(115,810)
9 CR-3 Projected Expense				0	0	0	0	0	0	0	0	0	0	0	0	0
10 ISFSI Return				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
11 Vandolah Capacity Purchase			June 2012 - May 2027	2,939,299	2,876,217	1,958,481	1,943,807	2,807,348	5,839,892	5,903,915	5,834,456	2,761,749	1,944,121	2,042,628	2,997,569	39,849,482
12 Schedule H Capacity Sales - Tallahassee	1	-1	on-going no term date	0	0	(32,469)	0	0	0	0	(32,125)	(5,587)	(61,457)	0	0	(131,637)
13 Shady Hills Tolling	1	517	4/1/07-4/30/24	1,973,160	1,973,160	1,973,160	802,440	1,912,680	3,911,760	3,904,200	3,904,200	1,821,960	1,371,600	1,371,600	1,976,940	26,896,860
14 RidgeGen Agreement Termination				708,094	704,621	701,149	697,676	694,203	690,731	687,052	683,585	680,117	676,649	673,181	669,714	8,266,772
15 Hamilton SoBRA True-Up				0	0	0	0	0	0	0	0	0	0	0	0	0
16 Columbia SoBRA True-Up				0	0	0	0	0	0	0	0	(133,589)	0	0	0	(133,589)
17 Lake Placid SoBRA True-Up				0	0	0	0	0	0	0	0	(213,688)	0	0	0	(213,688)
18 Trenton SoBRA True-Up				0	0	0	0	0	0	0	0	(597,927)	0	0	0	(597,927)
19 Debary SoBRA True-Up				0	0	0	0	0	0	0	0	(77,810)	0	0	0	(77,810)
20 State Corporate Income Tax Change				0	0	(3,491,633)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(5,586,617)
TOTAL				37,350,944	38,831,881	31,654,613	33,741,670	34,648,275	42,036,580	43,398,675	44,184,870	39,254,898	34,277,764	34,418,578	36,813,252	450,611,998

Docket No. 20210001-EI
Witness: Dean
Exhibit No. (GPD-4T)
Sheet 1 of 2

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
January 2020 through June 2020

Adjusted
Retail

	\$000's	Ratio	Cost Rate	Weighted Cost	Pre-Tax Weighted Cost Rate
Common Equity	\$ 4,874,577	41.01%	10.50%	4.31%	5.71%
Long Term Debt	4,845,025	40.77%	4.70%	1.92%	1.92%
Short Term Debt	(59,427)	-0.50%	-0.36%	0.00%	0.00%
Customer Deposits - Active	176,757	1.49%	2.38%	0.04%	0.04%
Customer Deposits - Inactive	1,853	0.02%	0.00%	0.00%	0.00%
Deferred Tax	2,026,313	17.05%	0.00%	0.00%	0.00%
ITC	19,806	0.17%	7.71%	0.01%	0.01%
	<u>\$ 11,884,905</u>	<u>100.00%</u>		<u>6.27%</u>	<u>7.67%</u>

Total Debt 1.97% 1.97%
Total Equity 4.31% 5.71%

Note> May 2019 DEF Surveillance Report capital structure and cost rates. See Amended Unopposed Joint Motion to Modify Order No. PSC-2012-0425-PAA-EU.

Duke Energy Florida, LLC
 Capital Structure and Cost Rates Applied to Capital Projects
 July 2020 through December 2020

	Adjusted Retail		Cost Rate	Weighted Cost	Pre-Tax Weighted Cost Rate
	\$000's	Ratio			
Common Equity	\$ 5,587,139	41.48%	10.50%	4.36%	5.77%
Long Term Debt	5,219,535	38.75%	4.62%	1.79%	1.79%
Short Term Debt	228,721	1.70%	2.10%	0.04%	0.04%
Customer Deposits - Active	184,177	1.37%	2.43%	0.03%	0.03%
Customer Deposits - Inactive	1,821	0.01%	0.00%	0.00%	0.00%
Deferred Tax	2,189,709	16.26%	0.00%	0.00%	0.00%
ITC	58,311	0.43%	7.66%	0.03%	0.03%
	<u>\$ 13,469,412</u>	<u>100.00%</u>		<u>6.25%</u>	<u>7.66%</u>
Total Debt				1.89%	1.89%
Total Equity				4.36%	5.77%

Note> May 2020 DEF Surveillance Report capital structure and cost rates. See Amended Unopposed Joint Motion to Modify Order No. PSC-2012-0425-PAA-EU.

Duke Energy Florida, LLC
Fuel Cost Recovery
Actual / Estimated True-Up
January through December 2021

Schedule E1-B – Calculation of Estimated True-up
Schedule E2 – Fuel Cost Recovery Clause Calculation by Month
Schedule E3 – Generating System Comparative Data
Schedule E4 – System Net Generation & Fuel Cost by Month
Schedule E5 – Inventory Analysis
Schedule E6 – Fuel Cost of Power Sold
Schedule E7 – Purchased Power
Schedule E8 – Energy Payments to Qualifying Facilities
Schedule E9 – Economy Energy Purchases
Capital Structure and Cost Rates Applied to Capital Projects
(Order No. PSC-0165-PAA-EU)

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	<u>94,625,147</u>	<u>100,283,924</u>	<u>111,915,742</u>	<u>103,764,312</u>	<u>132,535,158</u>	<u>142,559,279</u>	<u>685,683,562</u>
(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)	<u>2,883,105</u>	<u>2,760,713</u>	<u>2,895,026</u>	<u>2,951,952</u>	<u>3,158,561</u>	<u>3,711,484</u>	<u>18,360,842</u>
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 (Net of Revenue Taxes)	87,983,471	83,155,269	87,192,862	89,476,925	96,745,142	114,558,977	559,112,646
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	<u>92,706,447</u>	<u>87,878,245</u>	<u>91,915,838</u>	<u>94,199,901</u>	<u>101,468,118</u>	<u>119,281,953</u>	<u>587,450,502</u>
(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 (Line A6 * Line B4 * Line Loss Multiplier)	94,654,481	99,770,319	111,879,910	103,751,849	132,492,725	141,857,680	684,406,963
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	<u>(1,946,408)</u>	<u>(11,891,529)</u>	<u>(19,965,269)</u>	<u>(9,554,733)</u>	<u>(31,027,617)</u>	<u>(22,580,331)</u>	<u>(96,965,888)</u>
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	<u>(5,090,285)</u>	<u>(10,180,570)</u>	<u>(15,270,855)</u>	<u>(20,361,140)</u>	<u>(25,451,425)</u>	<u>(30,541,710)</u>	<u>(30,541,710)</u>
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	<u>\$14,542,893</u>	<u>(2,438,921)</u>	<u>(\$27,494,475)</u>	<u>(\$42,139,494)</u>	<u>(\$78,257,396)</u>	<u>(\$105,928,013)</u>	<u>(105,928,013)</u>

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	\$ 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)	(79,668,669)
	3	Fuel Cost of Purchased Power	6,072,483	10,823,277	2,250,881	869,664	1,101,345	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	104,872,798
	4	Energy Cost of Economy Purchases	501,507	810,800	289,767	261,448	217,100	13,701,073
	5	Adjustments to Fuel Cost	1,105,933	1,107,496	1,093,015	1,084,215	1,080,232	15,299,973
	6	TOTAL FUEL & NET POWER TRANSACTIONS	<u>140,356,784</u>	<u>155,371,139</u>	<u>131,703,144</u>	<u>115,834,636</u>	<u>102,614,225</u>	<u>1,441,178,569</u>
		(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	39,363,435
	2	Non-Jurisdictional mWh Sales	<u>41,049</u>	<u>60,583</u>	<u>20,825</u>	<u>2,186</u>	<u>692</u>	<u>165,711</u>
	3	TOTAL SALES (Lines B1 + B2)	<u>3,867,774</u>	<u>3,989,367</u>	<u>3,884,296</u>	<u>3,603,893</u>	<u>2,991,230</u>	<u>39,529,146</u>
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.94%	98.48%	99.46%	99.94%	99.98%	99.58%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	118,157,880	121,309,137	119,292,463	126,479,329	105,017,236	1,248,765,535
	2	True-Up Provision	5,090,285	5,090,285	5,090,285	(8,077,661)	(8,077,661)	21,579,592
	2a	Incentive Provision	<u>(367,309)</u>	<u>(367,309)</u>	<u>(367,309)</u>	<u>(367,309)</u>	<u>(367,313)</u>	<u>(4,407,712)</u>
	3	FUEL REVENUE APPLICABLE TO PERIOD	<u>122,880,856</u>	<u>126,032,113</u>	<u>124,015,439</u>	<u>118,034,360</u>	<u>96,572,266</u>	<u>1,265,937,415</u>
		(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	1,441,178,569
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	<u>138,907,885</u>	<u>153,052,340</u>	<u>131,028,625</u>	<u>115,797,550</u>	<u>102,622,428</u>	<u>1,435,417,703</u>
	6	Over/(Under) Recovery (Line C3 - Line C5)	(16,027,029)	(27,020,228)	(7,013,185)	2,236,810	(6,050,162)	(169,480,294)
	7	Interest Provision	<u>(5,822)</u>	<u>(7,153)</u>	<u>(8,259)</u>	<u>(8,304)</u>	<u>(7,996)</u>	<u>(55,171)</u>
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	<u>(16,032,852)</u>	<u>(27,027,381)</u>	<u>(7,021,444)</u>	<u>2,228,506</u>	<u>(6,058,158)</u>	<u>(169,535,465)</u>
	9	Plus: Prior Period Balance	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587
	10	Plus: Cumulative True-Up Provision	<u>(35,631,995)</u>	<u>(40,722,280)</u>	<u>(45,812,565)</u>	<u>(37,734,904)</u>	<u>(29,657,243)</u>	<u>(21,579,591)</u>
	11	Subtotal Prior Period True-up	(14,052,408)	(19,142,693)	(24,232,978)	(16,155,318)	(8,077,657)	(5)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	<u>(\$127,051,152)</u>	<u>(\$159,168,817)</u>	<u>(\$171,280,547)</u>	<u>(\$160,974,380)</u>	<u>(\$158,954,877)</u>	<u>(169,535,467)</u>

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 through December 2021

	DOLLARS				mWh				c/kWh			
	Actual/ Estimated	Projection Filing	Difference		Actual/ Estimated	Projection Filing	Difference		Actual/ Estimated	Projec ion Filing	Difference	
			Amount	%			Amount	%			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 (Excl. Econ & Cogens) (E7)	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%
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 es (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 (LINES 10 + 10a + 10b + 11)	(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%
13 Net Inadvertent Interchange					0	0	-					
14 TOTAL FUEL & NET POWER TRANSACTIONS (LINES 4 + 8 + 12 + 13)	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%
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	Jurisdictional 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

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		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

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		Estimated	Estimated	Estimated	Estimated	Estimated	Estimated	
		Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	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

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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

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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

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVA L 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	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

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(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	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
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(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
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(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	Act	Act	Act	Act	Act	
		Jan-21	Feb-21	Mar-21	Apr-21	May-21	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 OIL							
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 INVENTORY:							
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 INVENTORY:							
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)	(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	(A) FUEL COST	(B) TOTAL COST	TOTAL \$ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST \$ (6) x (7)(B)	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) 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		(8) TOTAL \$ FOR FUEL ADJ (6) x (7)(A)	(9) TOTAL COST \$ (6) x (7)(B)	(10) REFUNDABLE GAIN ON POWER SALES \$
						(A) FUEL COST	(B) TOTAL COST			
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) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) C/KWH		(9) TOTAL \$ FOR FUEL ADJ (7) x (8)(B)
							(A) FUEL COST	(B) TOTAL COST	
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 FIRM	(8) C/KWH		(9) TOTAL \$ FOR FUEL ADJ (7) x (8)(B)
							(A) FUEL COST	(B) TOTAL COST	
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) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) C/KWH		(9) TOTAL \$ FOR FUEL ADJ (7) x (8)(A)
							(A) ENERGY COST	(B) TOTAL COST	
Jan-21 Act	QUAL. FACILITIES	COGEN	207,778			207,778	3.633	17.411	7,548,154
Feb-21 Act	QUAL. FACILITIES	COGEN	203,273			203,273	3.592	17.682	7,301,243
Mar-21 Act	QUAL. FACILITIES	COGEN	181,241			181,241	4.468	20.267	8,097,325
Apr-21 Act	QUAL. FACILITIES	COGEN	177,610			177,610	4.003	20.125	7,109,630
May-21 Act	QUAL. FACILITIES	COGEN	219,951			219,951	3.868	16.887	8,508,302
Jun-21 Act	QUAL. FACILITIES	COGEN	211,457			211,457	4.328	17.870	9,152,559
Jul-21 Est	QUAL. FACILITIES	COGEN	229,907			229,907	4.247	16.702	9,763,058
Aug-21 Est	QUAL. FACILITIES	COGEN	229,907			229,907	4.262	16.717	9,797,946
Sep-21 Est	QUAL. FACILITIES	COGEN	222,491			222,491	4.212	17.082	9,371,619
Oct-21 Est	QUAL. FACILITIES	COGEN	217,043			217,043	4.280	17.474	9,289,938
Nov-21 Est	QUAL. FACILITIES	COGEN	224,068			224,068	4.126	16.906	9,245,904
Dec-21 Est	QUAL. FACILITIES	COGEN	237,161			237,161	4.085	16.159	9,687,120
TOTAL	QUAL. FACILITIES	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)
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	TRANSACTION COST		TOTAL \$ FOR FUEL ADJ (4) x (5)	COST IF GENERATED		FUEL SAVINGS (8)(B) - (7)	
				ENERGY COST C/KWH	TOTAL COST C/KWH		(A) C/KWH	(B) \$		
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) MONTH	(2) PURCHASE	(3) TYPE & SCHED	(4) TOTAL MWH PURCHASED	(5) TRANSACTION COST		(7) TOTAL \$ FOR FUEL ADJ (4) x (5)	(8) COST IF GENERATED		(9) FUEL SAVINGS (8)(B) - (7)
				ENERGY COST C/KWH	TOTAL COST C/KWH		(A) C/KWH	(B) \$	
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			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			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			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			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			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			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			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)	(2)	(3)	(4)	(5)	(6)
	Jurisdictional Rate Base Adjusted Retail (\$000s)	Cap Ratio	Cost Rate	Weighted Cost	Revenue Requirement Rate	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%

	<u>Breakdown of Revenue Requirement Rate of Return between Debt and Equity:</u>	
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)

	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 <u>Base Production Level Capacity Costs</u>													
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 <u>Intermediate Production Level Capacity Costs</u>													
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 Jurisdiction. 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 Jurisdiction. Capacity Costs	3,599,152	3,599,152	2,145,816	2,145,816	2,353,436	-	-	-	-	-	-	-	13,843,372
16 <u>Peaking Production Level Capacity Costs</u>													
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 <u>Other Capacity Costs</u>													
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 <u>ISFSI Revenue Requirement</u> 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.

	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 <u>Base Production Level Capacity Costs</u>													
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 <u>Intermediate Production Level Capacity Costs</u>													
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 Jurisdickt. 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 Jurisdickt. Capacity Costs	3,509,199	3,627,019	2,118,327	2,119,270	2,325,263	(384,867)	-	-	-	-	-	-	13,314,211
16 <u>Peaking Production Level Capacity Costs</u>													
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 <u>Other Capacity Costs</u>													
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 Requirement³	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 <u>Capacity Revenues</u>													
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 <u>True-Up Provision</u>													
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 (ORLACOG)	Sep-93	Dec-23	QF	Purch	115.00
2	Orange Cogen (ORANGE)	Jul-95	Dec-25	QF	Purch	104.00
3	Pasco County Resource Recovery (PASCO)	Jan-95	Dec-24	QF	Purch	23.00
4	Pinellas County Resource Recovery (PINCO)	Jan-95	Dec-24	QF	Purch	54.75
5	Polk Power Partners, L. P. (MULBERRY/ROYST)	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

	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
6 Capacity Costs			
7 Base Production Level Capacity Costs			
8 Orange Cogen (ORANGE CO)	74,266,524	74,266,522	2
9 Orlando Cogen Limited (ORLACOG)	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
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)
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
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
42 Subtotal Jurisdictional Capacity Costs (Line 15+22+29+40)	482,181,513	479,983,370	2,198,143
44 ISFSI Revenue Requirement³	6,879,837	6,879,837	(0)
46 Total Jurisdictional Capacity Costs (Line 42+44)	489,061,350	486,863,207	2,198,143
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
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
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
Fuel and Capacity Cost Recovery Factor
January through December 2022

PART 1 – 2022 FUEL PRICE FORECAST ASSUMPTIONS

Projected Market Price by Fuel Type

PROJECTED MARKET PRICE BY FUEL TYPE

Month	Light Oil		Coal Crystal River 4 & 5		Natural Gas
	\$/barrel	\$/mmbtu	\$/ton	\$/mmbtu	\$/mmbtu
Jan 2022	84.76	14.55	59.39	2.54	4.14
Feb 2022	84.80	14.56	59.26	2.54	4.05
Mar 2022	84.56	14.52	59.19	2.54	3.78
Apr 2022	83.92	14.41	58.70	2.54	3.16
May 2022	83.66	14.36	58.48	2.55	3.06
Jun 2022	83.58	14.35	58.74	2.57	3.09
Jul 2022	83.66	14.36	58.48	2.57	3.13
Aug 2022	83.62	14.36	59.23	2.61	3.13
Sep 2022	83.63	14.36	59.51	2.63	3.12
Oct 2022	83.42	14.32	59.67	2.63	3.14
Nov 2022	83.14	14.27	60.04	2.65	3.19
Dec 2022	82.62	14.18	60.42	2.67	3.31
Average	83.78	14.38	59.26	2.59	3.36

Light Oil: The above base market oil price forecasts are the NYMEX forwards. Oil prices projected within the fuel forecast are based on expected contract structures and specifications, and incorporate transportation costs.

Coal: Coal price projections are based on independent third party providers and take into account current coal supply, transportation agreements and forecasted deliveries. Crystal River Units 4 and 5 have operating scrubbers that allow for use of higher sulfur coal.

Natural Gas: The base market natural gas price forecast is the NYMEX Henry Hub forward. This table includes natural gas market commodity prices only; however, the fuel forecast also incorporates transportation costs. Forecast prices are based on expected contract specifications. Firm transportation costs for Florida Gas Transmission, Gulfstream and Sabal Trail pipelines are based on expected tariff rates and market conditions.

DUKE ENERGY FLORIDA, LLC

Fuel Cost Recovery

January through December 2022

PART 2 - 2022 FUEL COST RECOVERY SCHEDULES

Schedule E1 – Fuel Cost Recovery Clause Calculation

Schedule E1-A – Calculation of Total True-up

Schedule E1-B – Calculation of Prior Year Estimated True-up

Schedule E1-C – Calculation of GPIF & True-up Factors

Schedule E1-D – Calculation of Levelized Fuel Adjustment Factors

Schedule E1-E – Calculation of Factors for Metering Voltage and Time of Use

Schedule E1-F – Calculation of Jurisdictional Delivery Loss Multipliers

Schedule E2 – Fuel Cost Recovery Clause Calculation by Month

Schedule E3 – Generating System Comparative Data

Schedule E4 – System Net Generation & Fuel Cost by Month

Schedule E5 – Inventory Analysis

Schedule E6 – Fuel Cost of Power Sold

Schedule E7 – Purchased Power

Schedule E8 – Energy Payments to Qualifying Facilities

Schedule E9 – Economy Energy Purchases

Schedule E10 – Residential Bill Comparison

Calculation of Inverted Residential Fuel Rate

Schedule H1 – Generating System Comparative Data

Capital Structure and Cost Rates Applied to Capital Projects

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2022 through December 2022

	DOLLARS	mWh	CENTS/KWH
1. Fuel Cost of System Net Generation (E3)	1,342,122,966	40,554,861	3.3094
2. Coal Car Investment	0	0	0.0000
3. Adjustment to Fuel Cost	12,294,429	0	0.0000
4. TOTAL COST OF GENERATED POWER	1,354,417,395	40,554,861	3.3397
5. Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)	11,259,068	166,907	6.7457
6. Energy Cost of Economy Purchases (E9)	2,973,141	66,432	4.4755
7. Payments to Qualifying Facilities (E8)	114,130,163	2,664,397	4.2835
8. TOTAL COST OF PURCHASED POWER	128,362,372	2,897,737	4.4297
9. TOTAL AVAILABLE mWh		43,452,598	
10. Fuel Cost of Economy Sales (E6)	(9,080,256)	(251,831)	3.6057
10a. Gain on Economy Sales (E6)	(2,460,928)	(251,831) *	0.9772
10b. Gain on Total Power Sales - 20% (E6)	172,656		
11. Fuel Cost of Stratified Sales (E6)	(39,687,742)	(1,411,321)	2.8121
12. TOTAL FUEL COST AND GAINS ON POWER SALES	(51,056,270)	(1,663,152)	3.0699
13. Net Inadvertent Interchange			
14. TOTAL FUEL AND NET POWER TRANSACTIONS	1,431,723,498	41,789,446	3.4260
15. Net Unbilled	652,674 *	(46,267)	0.0017
16. Company Use	5,706,535 *	(164,698)	0.0145
17. T & D Losses	75,588,626 *	(2,206,272)	0.1920
18. Adjusted System Sales	1,431,723,498	39,372,209	3.6342
19. Wholesale Sales (Excluding Supplemental Sales)	(597,066)	(17,150)	3.4814
20. Jurisdictional Sales	1,431,126,432	39,355,059	3.6364
21. Jurisdictional Sales Adjusted for Line Losses x 1.00028	1,431,527,147	39,355,059	3.6375
22. Prior Period True-Up (Sch E1-A)	123,418,788	39,355,059	0.3136
23. Total Jurisdictional Fuel Cost	1,554,945,935	39,355,059	3.9511
24. GPIF **	2,657,279	39,355,059	0.0068
25. CEC Bill Credit	11,109,749	39,355,059	0.0282
26. Fuel Factor Adjusted including GPIF & CEC Bill Credit	1,568,712,963	39,355,059	3.9861
27. Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)			3.9860

* For Informational Purposes Only

** Based on Jurisdictional Sales

Duke Energy Florida, LLC
Calculation of Total True-Up
(Projected Period)
Estimated for the Period of : January 2022 through December 2022

1. Estimated Over/(Under) Recovery January - December 2021 (Schedule E1-B, Page 2 of 2, Section C, Lines 8 and 12 - Dec 21)	\$	(246,837,576)
2. Over/(Under) Recovery to be Included in 2022 Rates (Line 1 / 2)		(123,418,788)
3. Jurisdictional mWh Sales (Projected Period)	mWh	39,355,059
4. True-Up Factor (Line 2 / Line 3)	Cents/kWh	0.314

Note: Commission approved DEF's approximate \$39.5M recovery of prior year true-up in Order No. PSC-2021-0328-PCO-EI.
Therefore, the estimated \$246.8M above is the only remaining under-recovery, and is for the current year (2021).

Duke Energy Florida, LLC
Calculation of Estimated True-Up
7 Months Actual and 5 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 (Net of Revenue Taxes)	87,983,471	83,155,269	87,192,862	89,476,925	96,745,142	114,558,977	559,112,646
	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 (Line A6 * Line B4 * Line Loss Multiplier)	94,654,481	99,770,319	111,879,910	103,751,849	132,492,725	141,857,680	684,406,963
	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
7 Months Actual and 5 Months Estimated
January 2021 - December 2021

			Jul Actual	Aug Estimated	Sep Estimated	Oct Estimated	Nov Estimated	Dec Estimated	12 Month Period
A	1	Fuel Cost of System Generation	\$ 148,931,960	\$ 162,015,816	\$ 144,717,338	\$ 125,656,319	\$ 107,819,732	\$ 111,023,612	\$ 1,404,339,921
	2	Fuel Cost of Power Sold	(11,387,686)	(11,908,122)	(10,340,321)	(8,127,259)	(6,569,483)	(3,948,859)	(85,215,543)
	3	Fuel Cost of Purchased Power	10,776,054	12,350,400	3,333,771	805,620	1,665,071	55,385	75,611,032
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	8,708,077	10,325,857	9,923,825	9,762,720	9,747,136	10,234,007	106,418,835
	4	Energy Cost of Economy Purchases	4,321,612	1,151,658	611,091	437,793	344,471	377,939	18,592,667
	5	Adjustments to Fuel Cost	1,109,677	1,107,496	1,093,015	1,084,215	1,080,232	1,076,898	15,303,717
	6	TOTAL FUEL & NET POWER TRANSACTIONS	162,459,696	175,043,104	149,338,719	129,619,408	114,087,160	118,818,982	1,535,050,631
(Sum of Lines A1 Through A5)									
B	1	Jurisdictional mWh Sales	3,774,783	3,928,784	3,863,471	3,601,707	2,990,539	2,830,489	39,311,492
	2	Non-Jurisdictional mWh Sales	48,760	60,583	20,825	2,186	692	1,255	173,423
	3	TOTAL SALES (Lines B1 + B2)	3,823,543	3,989,367	3,884,296	3,603,893	2,991,230	2,831,743	39,484,915
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.72%	98.48%	99.46%	99.94%	99.98%	99.96%	99.56%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	117,399,908	121,309,137	135,671,555	126,479,329	105,017,236	99,396,843	1,264,386,654
	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	122,122,884	126,032,113	140,394,531	118,034,360	96,572,266	90,951,874	1,281,558,534
	(Sum of Lines C1 Through C2a)								
	4	Fuel & Net Power Transactions (Line A6)	162,459,696	175,043,104	149,338,719	129,619,408	114,087,160	118,818,982	1,535,050,631
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	160,425,118	172,430,716	148,573,879	129,577,908	114,096,280	118,804,710	1,528,315,574
	6	Over/(Under) Recovery (Line C3 - Line C5)	(38,302,235)	(46,398,604)	(8,179,348)	(11,543,548)	(17,524,014)	(27,852,836)	(246,757,046)
	7	Interest Provision	(7,657)	(10,502)	(12,445)	(12,948)	(13,336)	(14,214)	(80,529)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(38,309,892)	(46,409,105)	(8,191,793)	(11,556,496)	(17,537,350)	(27,867,050)	(246,837,576)
	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	(\$149,328,192)	(\$200,827,583)	(\$214,109,661)	(\$217,588,496)	(\$227,048,186)	(\$246,837,576)	(246,837,576)	

Duke Energy Florida, LLC
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period of : January 2022 through December 2022

1. TOTAL AMOUNT OF ADJUSTMENTS:

A. Generating Performance Incentive Reward / (Penalty)	\$	2,657,279
B. True-Up (Over) / Under Recovery	\$	123,418,788
C. CEC Bill Credit	\$	11,109,749

2. JURISDICTIONAL mWh SALES	mWh	39,355,059
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3. ADJUSTMENT FACTORS:

A. Generating Performance Incentive Factor	Cents/kWh	0.007
B. True-Up Factor	Cents/kWh	0.314
C. CEC Bill Credit	Cents/kWh	0.028

Duke Energy Florida, LLC
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January 2022 through December 2022

1.	Period Jurisdictional Fuel Cost (Schedule E-1, line 21)	\$	1,431,565,051	
1a.	Prior Period True-up (E1, Line 22)	\$	123,418,788	
2.	Generating Performance Incentive Factor (GPIF) (E1, Line 24)	\$	2,657,279	
3.	CEC Bill Credit	\$	<u>11,109,749</u>	
4.	Total Amount to be Recovered	\$	1,568,750,867	
5.	Jurisdictional Sales (January - December 2018)		39,355,059	mWh
6.	Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)		3.986	Cents/kWh
7.	Effective Jurisdictional Sales (See Below)		39,299,752	mWh
LEVELIZED FUEL FACTORS:				
8.	Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)		3.992	Cents/kWh
9.	Fuel Factor at Primary Metering		3.952	Cents/kWh
10.	Fuel Factor at Transmission Metering		3.912	Cents/kWh
TIERED FUEL FACTORS:				
11.	Fuel Factor - First Tier (0-1000 kWh)		3.681	Cents/kWh
12.	Fuel Factor - Second Tier (Over 1000 kWh)		4.751	Cents/kWh

METERING VOLTAGE:	JURISDICTIONAL SALES (mWh)	
	METER	SECONDARY
Distribution Secondary	34,832,106	34,832,106
Distribution Primary	3,514,929	3,479,780
Transmission	<u>1,008,026</u>	<u>987,866</u>
Total	<u>39,355,061</u>	<u>39,299,752</u>

Duke Energy Florida, LLC
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January 2022 through December 2022

Line:	Metering Voltage	-----Time of Use-----					
		First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	On-Peak Multiplier 1.281	Off-Peak Multiplier 0.984	Super Off-Peak Multiplier 0.732
1.	Distribution Secondary	3.681	4.751	3.992	5.114	3.928	2.922
2.	Distribution Primary	--	--	3.952	5.063	3.889	2.893
3.	Transmission	--	--	3.912	5.011	3.849	2.864
4.	Lighting Service	--	--	3.700	--	--	--

Line 4 calculated at secondary rate of 3.992 * (13.2% * On-Peak Multiplier 1.281 + 48.6% * Off-Peak Multiplier 0.984+ 38.2% * Super Off-Peak Multiplier 0.732).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

ON-PEAK PERIOD				OFF-PEAK PERIOD				SUPER OFF-PEAK PERIOD				TOTAL
Mo/Yr	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
Jan-22	783,442	31,251,505	3.989	2,216,953	63,419,991	2.861	0	0	0.000	3,000,395	94,671,496	3.155
Feb-22	704,914	27,139,194	3.850	1,956,339	55,501,386	2.837	0	0	0.000	2,661,253	82,640,580	3.105
Mar-22	314,866	14,779,807	4.694	2,206,200	65,117,469	2.952	402,123	9,422,316	2.343	2,923,189	89,319,592	3.056
Apr-22	323,207	11,829,358	3.660	2,278,968	57,882,289	2.540	365,467	7,267,516	1.989	2,967,641	76,979,163	2.594
May-22	374,052	13,510,773	3.612	2,798,562	77,746,762	2.778	413,801	8,502,590	2.055	3,586,416	99,760,125	2.782
Jun-22	434,821	14,379,524	3.307	3,025,507	86,746,636	2.867	515,356	10,535,077	2.044	3,975,684	111,661,237	2.809
Jul-22	408,902	14,246,161	3.484	3,353,846	96,822,734	2.887	497,823	10,345,654	2.078	4,260,571	121,414,549	2.850
Aug-22	467,055	14,576,778	3.121	3,245,263	94,449,368	2.910	560,614	11,539,707	2.058	4,272,932	120,565,853	2.822
Sep-22	411,272	14,509,689	3.528	3,040,643	87,001,261	2.861	493,843	10,088,712	2.043	3,945,758	111,599,662	2.828
Oct-22	347,783	13,302,689	3.825	2,667,038	73,438,937	2.754	413,368	8,369,080	2.025	3,428,189	95,110,707	2.774
Nov-22	287,395	10,639,373	3.702	2,123,407	56,825,340	2.676	353,445	7,058,918	1.997	2,764,247	74,523,631	2.696
Dec-22	773,407	23,975,612	3.100	2,162,087	49,948,456	2.310	0	0	0.000	2,935,494	73,924,068	2.518
TOTAL	5,631,116	204,140,463	3.625	31,074,813	864,900,629	2.783	4,015,840	83,129,569	2.070	40,721,769	1,152,170,662	2.829
MARGINAL FUEL COST WEIGHTING MULTIPLIER			ON-PEAK 1.281	OFF-PEAK 0.984			SUPER OFF-PEAK 0.732			AVERAGE 1.000		

Duke Energy Florida, LLC
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2020
Estimated for the Period of : January 2022 through December 2022

		Energy Delivered @ Billing Level			% of Total	Delivery Efficiency	Energy Required @ Source Level	% of Total	Jurisdictional Loss Multiplier
		Billed mWh	Unbilled mWh	Total mWh					
Retail									
Transmission		990,477	6,080	996,557		0.9859311	1,010,778		
Distribution Primary		3,247,543	19,935	3,267,478		0.9759311	3,348,062		
Distribution Secondary		34,992,191	214,818	35,207,009		0.9361197	37,609,517		
Total Retail		39,230,211	240,833	39,471,044	99.51%	0.9404953	41,968,357	99.53%	1.00028
						5.95%			
Wholesale									
Generation Level		166,928	-	166,928		1.0000000	166,928		
Transmission		-	-	-		0.9859311	-		
Distribution Primary		28,950	-	28,950		0.9759311	29,664		
Distribution Secondary		-	-	-			-		
Total Wholesale		195,878	-	195,878	0.49%	0.9963682	196,592	0.47%	0.94418
						0.36%			
Subtotal Class		39,426,089	240,833	39,666,922	100.00%	0.9407558	42,164,949	100.00%	1.00000
						5.92%			
Non-Class									
SEPA	Transmission	34,331	-	34,331		0.9859311	34,821		
Homestead Base & Int	Generation	-	-	-		1.0000000	-		
SECI - CC	Generation	941,179	-	941,179		1.0000000	941,179		
SECI - Base	Generation	-	-	-		1.0000000	-		
Reedy Creek Base & Int	Generation	391,850	-	391,850		1.0000000	391,850		
Reedy Creek Hines	Generation	-	-	-		1.0000000	-		
Reedy Creek Solar	Generation	29,280	-	29,280		1.0000000	29,280		
NSB - Peaking	Generation	-	-	-		1.0000000	-		
SECI - Intermediate	Generation	61,990	-	61,990		1.0000000	61,990		
SECI - Peaking	Generation	4,405	-	4,405		1.0000000	4,405		
TECO Base	Generation	1,227,875	-	1,227,875		1.0000000	1,227,875		
Interchange	Generation	(27,126)	-	(27,126)		1.0000000	(27,126)		
Company Use	Secondary	109,876	-	109,876		0.9361197	117,374		
Total Non-Class		2,773,660	-	2,773,660			2,781,648		
Total System									
		42,199,749	240,833	42,440,582		0.944245	44,946,597		

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2022 through December 2022

		Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	TOTAL
1	Fuel Cost of System Net Generation	\$113,799,787	\$99,804,117	\$115,722,673	\$94,776,397	\$112,546,922	\$120,985,329	\$129,745,432	\$132,098,034	\$122,516,669	\$108,106,826	\$93,200,947	\$98,819,833	\$1,342,122,966
1a	Adjustments to Fuel Cost	1,058,537	872,354	1,051,635	1,048,289	1,045,151	1,041,699	1,038,142	1,034,690	1,031,238	1,027,889	1,024,026	1,020,780	12,294,429
2	Fuel Cost of Power Sold	(2,243,052)	(1,431,152)	(1,309,603)	(625,223)	(737,119)	(707,444)	(617,339)	(957,543)	(866,661)	(755,420)	(613,995)	(676,633)	(11,541,184)
2a	Gain on Total Power Sales - 20%	0	0	0	0	0	19,193	26,327	40,835	36,960	32,216	26,184	28,856	210,570
2b	Fuel Cost of Stratified Sales	(2,442,070)	(2,487,936)	(4,413,999)	(2,170,530)	(2,428,864)	(3,434,300)	(5,134,465)	(4,834,350)	(3,759,657)	(3,658,545)	(2,169,559)	(2,753,466)	(39,687,742)
3	Fuel Cost of Purchased Power (Excl Economy)	402,859	75,561	201,125	499,356	1,764,382	1,268,435	1,833,608	1,105,000	1,551,296	1,306,864	1,200,194	50,388	11,259,068
3a	Energy Payments to Qualifying Facilities	10,295,502	8,720,904	8,889,132	8,358,583	9,871,035	9,570,424	9,892,305	9,855,911	9,546,078	9,555,749	9,539,620	10,034,922	114,130,163
4	Energy Cost of Economy Purchases	255,518	244,320	496,365	153,968	213,081	162,977	226,632	242,983	248,573	281,761	225,562	221,401	2,973,141
5	Total System Fuel & Net Power Transactions	\$121,127,081	\$105,798,168	\$120,637,328	\$102,040,840	\$122,274,587	\$128,906,312	\$137,010,642	\$138,585,560	\$130,304,495	\$115,897,339	\$102,432,980	\$106,746,080	\$1,431,761,412
6	Jurisdictional mWh Sold	3,058,718	2,679,834	2,672,815	2,700,863	3,064,339	3,593,950	3,907,433	4,123,437	4,004,058	3,675,248	3,059,413	2,814,952	39,355,059
7	Jurisdictional % of Total Sales	99.98%	99.97%	99.98%	99.97%	99.94%	99.94%	99.95%	99.95%	99.95%	99.94%	99.98%	99.96%	99.96%
8	Jurisdicitional Fuel & Net Power Transactions	121,102,855	105,766,429	120,613,200	102,010,227	122,201,223	128,828,969	136,942,137	138,516,267	130,239,343	115,827,801	102,412,493	106,703,381	1,431,164,325
9	Jurisdictional Loss Multiplier	1.00028	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	121,136,764	105,796,043	120,646,972	102,038,790	122,235,439	128,865,041	136,980,481	138,555,052	130,275,810	115,860,233	102,441,168	106,733,258	1,431,565,051
11	Adjusted System Sales	mWh 3,059,457	2,680,700	2,673,344	2,701,559	3,066,322	3,596,251	3,909,422	4,125,427	4,005,983	3,677,434	3,060,105	2,816,206	39,372,209
12	System Cost per kWh Sold	c/kWh 3.9591	3.9467	4.5126	3.7771	3.9876	3.5844	3.5046	3.3593	3.2527	3.1516	3.3474	3.7904	3.6365
13	Jurisdictional Loss Multiplier	x 1.00028	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 kWh Sold	c/kWh 3.9604	3.9479	4.5139	3.7780	3.9890	3.5856	3.5056	3.3602	3.2536	3.1524	3.3484	3.7917	3.6376
15	Prior Period True-Up	+ 0.3363	0.3838	0.3848	0.3808	0.3356	0.2862	0.2632	0.2494	0.2569	0.2798	0.3362	0.3654	0.3136
16	Total Jurisdictional Fuel Expense	c/kWh 4.2966	4.3316	4.8987	4.1588	4.3246	3.8718	3.7688	3.6096	3.5105	3.4323	3.6846	4.1570	3.9512
17	GPIF	+ 0.0072	0.0083	0.0083	0.0082	0.0072	0.0062	0.0057	0.0054	0.0055	0.0060	0.0072	0.0079	0.0068
18	CEC Bill Credit	+ 0.0000	0.0000	0.0132	0.0273	0.0507	0.0382	0.0349	0.0320	0.0307	0.0332	0.0338	0.0329	0.0282
19	Total Recovery Factor (rounded .001)	c/kWh 4.304	4.340	4.920	4.194	4.383	3.916	3.809	3.647	3.547	3.472	3.726	4.198	3.986

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2022 through December 2022

		Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Subtotal
1	FUEL COST OF SYSTEM NET GENERATION (\$)							
2	LIGHT OIL	861,707	944,542	15,563,088	865,156	754,219	1,076,237	20,064,949
3	COAL	15,467,529	15,133,404	21,664,435	18,349,980	20,884,131	20,145,173	111,644,652
4	GAS	97,470,551	83,726,171	78,495,150	75,561,261	90,908,572	99,763,919	525,925,624
5	OTHER	0	0	0	0	0	0	0
6	TOTAL \$	113,799,787	99,804,117	115,722,673	94,776,397	112,546,922	120,985,329	657,635,225
7	SYSTEM NET GENERATION (MWH)							
8	LIGHT OIL	4,382	4,454	108,450	4,233	3,794	5,131	130,444
9	COAL	563,687	549,337	802,058	647,508	743,611	709,914	4,016,115
10	GAS	2,326,687	1,984,206	1,839,164	2,088,282	2,580,748	3,029,565	13,848,652
11	SOLAR	101,114	122,852	171,413	220,368	236,866	209,546	1,062,159
12	OTHER	0	0	0	0	0	0	0
13	TOTAL MWH	2,995,870	2,660,849	2,921,086	2,960,391	3,565,019	3,954,156	19,057,370
14	UNITS OF FUEL BURNED							
15	LIGHT OIL BBL	8,090	8,940	141,549	8,190	7,082	10,468	184,319
16	COAL TON	238,922	233,813	344,184	290,707	335,026	321,037	1,763,689
17	GAS MCF	16,219,211	13,899,572	12,828,623	14,768,022	18,908,652	21,820,047	98,444,127
18	OTHER	0	0	0	0	0	0	0
19	BTUS BURNED (MMBTU)							
20	LIGHT OIL	47,129	52,085	824,578	47,708	41,242	60,982	1,073,724
21	COAL	5,593,407	5,457,188	8,009,487	6,716,559	7,679,455	7,323,291	40,779,387
22	GAS	16,219,211	13,899,572	12,828,623	14,768,022	18,908,652	21,820,047	98,444,127
23	OTHER	0	0	0	0	0	0	0
24	TOTAL MMBTU	21,859,747	19,408,845	21,662,688	21,532,289	26,629,349	29,204,320	140,297,238
25	GENERATION MIX (% MWH)							
26	LIGHT OIL	0.15%	0.17%	3.71%	0.14%	0.11%	0.13%	0.68%
27	COAL	18.82%	20.65%	27.46%	21.87%	20.86%	17.95%	21.07%
28	GAS	77.66%	74.57%	62.96%	70.54%	72.39%	76.62%	72.67%
29	SOLAR	3.38%	4.62%	5.87%	7.44%	6.64%	5.30%	5.57%
30	OTHER	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
31	TOTAL %	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
32	FUEL COST PER UNIT							
33	LIGHT OIL \$/BBL	106.52	105.65	109.95	105.64	106.50	102.81	108.86
34	COAL \$/TON	64.74	64.72	62.94	63.12	62.34	62.75	63.30
35	GAS \$/MCF	6.01	6.02	6.12	5.12	4.81	4.57	5.34
36	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	FUEL COST PER MMBTU (\$/MMBTU)							
38	LIGHT OIL	18.28	18.14	18.87	18.13	18.29	17.65	18.69
39	COAL	2.77	2.77	2.71	2.73	2.72	2.75	2.74
40	GAS	6.01	6.02	6.12	5.12	4.81	4.57	5.34
41	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	TOTAL \$/MMBTU	5.21	5.14	5.34	4.40	4.23	4.14	4.69
43	BTU BURNED PER KWH (BTU/KWH)							
44	LIGHT OIL	10,756	11,694	7,603	11,271	10,870	11,885	8,231
45	COAL	9,923	9,934	9,986	10,373	10,327	10,316	10,154
46	GAS	6,971	7,005	6,975	7,072	7,327	7,202	7,109
47	OTHER	0	0	0	0	0	0	0
48	TOTAL BTU/KWH	7,297	7,294	7,416	7,273	7,470	7,386	7,362
49	GENERATED FUEL COST PER KWH (C/KWH)							
50	LIGHT OIL	19.67	21.21	14.35	20.44	19.88	20.98	15.38
51	COAL	2.74	2.75	2.70	2.83	2.81	2.84	2.78
52	GAS	4.19	4.22	4.27	3.62	3.52	3.29	3.80
53	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
54	TOTAL C/KWH	3.80	3.75	3.96	3.20	3.16	3.06	3.45

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type

Estimated for the Period of : January 2022 through December 2022

		Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	Total
FUEL COST OF SYSTEM NET GENERATION (\$)								
1	LIGHT OIL	802,294	764,265	1,098,197	687,681	515,386	1,165,082	25,097,854
2	COAL	22,051,494	22,920,490	20,846,315	20,178,693	11,835,129	15,683,859	225,160,632
3	GAS	106,891,644	108,413,279	100,572,157	87,240,452	80,850,432	81,970,892	1,091,864,480
4	OTHER	0	0	0	0	0	0	0
5	TOTAL \$	129,745,432	132,098,034	122,516,669	108,106,826	93,200,947	98,819,833	1,342,122,966
SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL	3,865	4,002	5,277	2,814	2,201	5,828	154,432
7	COAL	785,813	806,548	724,103	695,968	395,298	538,416	7,962,261
8	GAS	3,230,240	3,246,004	3,010,285	2,533,536	2,206,742	2,261,517	30,336,977
9	SOLAR	208,617	197,975	180,242	174,496	148,032	129,671	2,101,192
10	OTHER	0	0	0	0	0	0	0
11	TOTAL MWH	4,228,536	4,254,529	3,919,908	3,406,814	2,752,273	2,935,432	40,554,861
UNITS OF FUEL BURNED								
12	LIGHT OIL BBL	7,593	7,252	10,792	6,348	4,416	11,454	232,174
13	COAL TON	355,000	365,151	328,660	316,479	175,853	238,304	3,543,136
14	GAS MCF	23,459,187	23,816,099	21,891,170	18,389,756	16,320,102	15,690,714	218,011,155
15	OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)								
16	LIGHT OIL	44,218	42,236	62,855	36,964	25,731	66,739	1,352,467
17	COAL	8,072,066	8,286,586	7,449,486	7,167,808	3,979,934	5,391,204	81,126,471
18	GAS	23,459,187	23,816,099	21,891,170	18,389,756	16,320,102	15,690,714	218,011,155
19	OTHER	0	0	0	0	0	0	0
20	TOTAL MMBTU	31,575,471	32,144,921	29,403,511	25,594,528	20,325,767	21,148,657	300,490,093
GENERATION MIX (% MWH)								
21	LIGHT OIL	0.09%	0.09%	0.14%	0.08%	0.08%	0.20%	0.38%
22	COAL	18.58%	18.96%	18.47%	20.43%	14.36%	18.34%	19.63%
23	GAS	76.39%	76.30%	76.80%	74.37%	80.18%	77.04%	74.81%
24	SOLAR	4.93%	4.65%	4.60%	5.12%	5.38%	4.42%	5.18%
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	105.66	105.39	101.76	108.33	116.71	101.72	108.10
28	COAL \$/TON	62.12	62.77	63.43	63.76	67.30	65.81	63.55
29	GAS \$/MCF	4.56	4.55	4.59	4.74	4.95	5.22	5.01
30	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU (\$/MMBTU)								
31	LIGHT OIL	18.14	18.10	17.47	18.60	20.03	17.46	18.56
32	COAL	2.73	2.77	2.80	2.82	2.97	2.91	2.78
33	GAS	4.56	4.55	4.59	4.74	4.95	5.22	5.01
34	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL \$/MMBTU	4.11	4.11	4.17	4.22	4.59	4.67	4.47
BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL	11,440	10,553	11,910	13,136	11,692	11,451	8,758
37	COAL	10,272	10,274	10,288	10,299	10,068	10,013	10,189
38	GAS	7,262	7,337	7,272	7,259	7,396	6,938	7,186
39	OTHER	0	0	0	0	0	0	0
40	TOTAL BTU/KWH	7,467	7,555	7,501	7,513	7,385	7,205	7,409
GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL	20.76	19.10	20.81	24.44	23.42	19.99	16.25
42	COAL	2.81	2.84	2.88	2.90	2.99	2.91	2.83
43	GAS	3.31	3.34	3.34	3.44	3.66	3.62	3.60
44	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL C/KWH	3.07	3.10	3.13	3.17	3.39	3.37	3.31

Duke Energy Florida, LLC
System Net Generation and Fuel Cost

Estimated for the Period of: Jan-22

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVA L 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	111,010	20.4	16.87	97.2	9,960 COAL	47,229 TONS	23.41	1,105,672	3,444,092	3.10
2 CRYSTAL RIVER	5	712	452,677	85.5	88.06	97.8	9,914 COAL	191,693 TONS	23.41	4,487,735	12,023,437	2 66
3 ANCLOTE	1	517	9,774	2.5	97.10	15.0	12,697 GAS	124,096 MCF	1.00	124,096	665,770	6 81
4 ANCLOTE	2	521	2,974	0.8	78.65	22.0	12,576 GAS	37,405 MCF	1.00	37,405	304,443	10 24
5 BARTOW	1-4	1,279	231	0.0	91.13	2.3	16,340 GAS	3,778 MCF	1.00	3,778	22,693	9 82
6 BARTOWCC	1	1279	562,152	59.1	94.52	62.4	7,164 GAS	4,027,199 MCF	1.00	4,027,199	24,193,362	4 30
7 CITRUS CC	1-2	1640	1,074,384	88.1	94.84	93.1	6,540 GAS	7,026,997 MCF	1.00	7,026,997	42,214,622	3 93
8 DEBARY	1-10	785	2,055	0.5	80.84	9.5	13,028 GAS	26,773 MCF	1.00	26,773	160,839	7 83
9 HINES	1-4	2,204	569,602	34.9	96.13	67.9	7,127 GAS	4,059,762 MCF	1.00	4,059,762	24,388,985	4 28
10 NT CITY	1-14	1,186	3,753	0.4	93.41	6.0	13,251 GAS	49,727 MCF	1.00	49,727	298,726	7 96
11 OSPREY	1	505	51,009	13.6	95.79	80.2	7,816 GAS	398,706 MCF	1.00	398,706	2,395,225	4.70
12 SUWANNEE CT	1-3	200	2,398	1.7	83.87	25.3	13,464 GAS	32,282 MCF	1.00	32,282	193,932	8 09
13 TIGER BAY	1	225	12,355	7.4	79.96	88.6	7,647 GAS	94,486 MCF	1.00	94,486	567,625	4 59
14 UNIV OF FLA.	1	47	36,000	103.0	96.77	106.4	9,389 GAS	338,000 MCF	1.00	338,000	2,064,329	5.73
15 BARTOW	1-4	228	212	0.3	91.13	13.0	15,871 LIGHT OIL	578 BBLS	5.82	3,363	53,748	25 37
16 BARTOW CC	1	1,279	0	59.1	94.52	62.4	0 LIGHT OIL	0 BBLS	5.82	0	46,240	0 00
17 BAYBORO	1-4	231	220	0.1	93.23	23.9	13,389 LIGHT OIL	507 BBLS	5.82	2,951	49,731	22 56
18 DEBARY	1-10	785	920	0.5	80.84	9.5	12,981 LIGHT OIL	2,050 BBLS	5.82	11,947	242,104	26 31
19 HINESCC	1-4	2,204	2,814	34.9	96.13	67.9	7,141 LIGHT OIL	3,449 BBLS	5.82	20,092	304,439	10 82
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	83	0.4	93.41	6.0	14,548 LIGHT OIL	207 BBLS	5.82	1,206	25,178	30 37
22 SUWANNEE CT	1-3	200	132	1.7	83.87	66.2	13,293 LIGHT OIL	302 BBLS	5.82	1,760	28,864	21 80
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT OIL	997 BBLS	5.82	5,810	111,403	0 00
24 SOLAR	1	738	101,114	18.4	0.00	36.7	0 SOLAR	0 N/A		0	0	0 00
25 TOTAL			2,995,870							21,859,747	113,799,787	3 80

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Feb-22

(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	145,415	29.6	24.71	92.8	9,976 COAL	62,154 TONS	23.34	1,450,677	4,322,167	2.97
2 CRYSTAL RIVER	5	712	403,922	84.4	88.93	95.7	9,919 COAL	171,659 TONS	23.34	4,006,511	10,811,237	2.68
3 ANCLOTE	1	517	14,131	4.1	98.00	15.4	12,609 GAS	178,172 MCF	1.00	178,172	912,842	6.46
4 ANCLOTE	2	521	1,063	0.3	96.67	15.7	13,810 GAS	14,677 MCF	1.00	14,677	248,397	23.37
5 BARTOW	1-4	1,279	164	0.0	89.73	2.1	16,709 GAS	2,740 MCF	1.00	2,740	16,496	10.06
6 BARTOWCC	1	1279	532,151	61.9	86.91	64.9	7,158 GAS	3,809,358 MCF	1.00	3,809,358	22,938,024	4.31
7 CITRUS CC	1-2	1640	835,591	75.8	77.30	96.8	6,540 GAS	5,465,136 MCF	1.00	5,465,136	32,908,282	3.94
8 DEBARY	1-10	785	2,130	0.6	80.97	9.1	13,169 GAS	28,049 MCF	1.00	28,049	168,899	7.93
9 H NES	1-4	2,204	510,641	34.7	95.09	70.6	7,113 GAS	3,632,230 MCF	1.00	3,632,230	21,871,451	4.28
10 INT CITY	1-14	1,186	2,064	0.3	92.76	5.5	13,713 GAS	28,304 MCF	1.00	28,304	170,433	8.26
11 OSPREY	1	505	51,585	15.2	95.17	82.4	7,873 GAS	406,151 MCF	1.00	406,151	2,445,636	4.74
12 SUWANNEE CT	1-3	200	2,368	1.9	85.18	25.8	13,388 GAS	31,701 MCF	1.00	31,701	190,886	8.06
13 TIGER BAY	1	225	398	0.3	31.71	88.5	8,100 GAS	3,227 MCF	1.00	3,227	19,434	4.88
14 UNIV OF FLA.	1	47	31,920	101.1	95.00	106.4	9,393 GAS	299,827 MCF	1.00	299,827	1,835,391	5.75
15 BARTOW	1-4	228	248	0.3	89.73	12.0	16,639 LIGHT OIL	708 BBLS	5.82	4,120	65,223	26.34
16 BARTOW CC	1	1,279	0	61.9	86.91	64.9	0 LIGHT OIL	0 BBLS	5.82	0	46,240	0.00
17 BAYBORO	1-4	231	230	0.1	93.48	24.8	13,595 LIGHT OIL	535 BBLS	5.82	3,120	52,417	22.84
18 DEBARY	1-10	785	948	0.6	80.97	9.1	13,097 LIGHT OIL	2,131 BBLS	5.82	12,413	251,252	26.51
19 H NESCC	1-4	2,204	2,850	34.7	95.09	70.6	7,171 LIGHT OIL	3,508 BBLS	5.82	20,438	309,468	10.86
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	20	0.3	92.76	5.5	15,567 LIGHT OIL	54 BBLS	5.82	316	10,500	51.72
22 SUWANNEE CT	1-3	200	159	1.9	85.18	79.4	13,436 LIGHT OIL	366 BBLS	5.82	2,133	34,709	21.86
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT OIL	1,638 BBLS	5.82	9,545	174,733	0.00
24 SOLAR	1	738	122,852	24.8	0.00	25.9	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			2,660,849							19,408,845	99,804,117	3.75

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Mar-22

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVA L 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	439,982	80.8	91.61	88.7	10,001 COAL	189,085 TONS	23 27	4,400,189	11,838,041	2.69
2 CRYSTAL RIVER	5	712	362,076	68.4	83.87	83.0	9,968 COAL	155,099 TONS	23 27	3,609,298	9,826,394	2.71
3 ANCLOTE	1	517	2,319	0.6	94.19	16.0	12,576 GAS	29,164 MCF	1 00	29,164	144,486	6.23
4 ANCLOTE	2	521	0	0.0	98.06	0.0	0 GAS	0 MCF	0 00	0	33,898	0.00
5 BARTOW	1-4	1,279	120	0.0	88.71	2.4	15,827 GAS	1,906 MCF	1 00	1,906	11,658	9.68
6 BARTOWCC	1	1279	318,403	44.2	66.13	47.4	7,342 GAS	2,337,699 MCF	1 00	2,337,699	14,298,931	4.49
7 CITRUS CC	1-2	1640	800,325	65.6	69.84	94.4	6,541 GAS	5,235,133 MCF	1 00	5,235,133	32,021,572	4.00
8 DEBARY	1-10	785	1,328	0.4	80.39	8.8	13,161 GAS	17,484 MCF	1 00	17,484	106,941	8.05
9 H NES	1-4	2,204	637,489	39.0	83.95	70.7	7,084 GAS	4,516,220 MCF	1 00	4,516,220	27,624,224	4.33
10 INT CITY	1-14	1,186	3,158	0.6	92.03	5.7	13,570 GAS	42,850 MCF	1 00	42,850	262,099	8.30
11 OSPREY	1	505	22,192	5.9	33.27	77.1	7,933 GAS	176,059 MCF	1 00	176,059	1,076,894	4.85
12 SUWANNEE CT	1-3	200	2,073	1.4	53.55	24.8	13,507 GAS	27,996 MCF	1 00	27,996	171,240	8.26
13 TIGER BAY	1	225	23,317	13.9	91.29	91.7	7,587 GAS	176,894 MCF	1 00	176,894	1,082,002	4.64
14 UNIV OF FLA.	1	47	28,440	81.3	75.45	106.3	9,396 GAS	267,218 MCF	1 00	267,218	1,661,205	5.84
15 BARTOW	1-4	228	210	0.2	88.71	13.2	15,953 LIGHT OIL	577 BBLS	5 82	3,356	53,511	25.44
16 BARTOW CC	1	1,279	102,531	44.2	66.13	47.4	7,342 LIGHT OIL	129,223 BBLS	5 82	752,774	14,345,343	13.99
17 BAYBORO	1-4	231	221	0.1	93.95	23.9	13,388 LIGHT OIL	507 BBLS	5 82	2,952	49,621	22.50
18 DEBARY	1-10	785	877	0.4	80.39	8.8	13,030 LIGHT OIL	1,961 BBLS	5 82	11,425	231,880	26.45
19 H NESCC	1-4	2,204	2,731	39.0	83.95	70.7	7,122 LIGHT OIL	3,339 BBLS	5 82	19,452	295,151	10.81
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	1,822	0.6	92.03	5.7	12,871 LIGHT OIL	4,025 BBLS	5 82	23,453	389,319	21.37
22 SUWANNEE CT	1-3	200	58	1.4	53.55	0.0	13,556 LIGHT OIL	136 BBLS	5 82	791	13,624	23.35
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT OIL	1,781 BBLS	5 82	10,375	184,639	0.00
24 SOLAR	1	813	171,413	28.3	0.00	27.9	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			2,921,086							21,662,688	115,722,673	3.96

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Apr-22

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVA L 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	358,886	68.1	93.67	74.4	10,378 COAL	161,213 TONS	23.10	3,724,696	10,105,951	2.82
2 CRYSTAL RIVER	5	712	288,622	56.3	87.00	66.9	10,366 COAL	129,494 TONS	23.10	2,991,863	8,244,029	2.86
3 ANCLOTE	1	517	20,782	5.6	96.00	17.9	12,244 GAS	254,460 MCF	1.00	254,460	1,050,811	5.06
4 ANCLOTE	2	521	0	0.0	93.00	0.0	0 GAS	0 MCF	0.00	0	250,788	0.00
5 BARTOW	1-4	1,279	74	0.0	90.25	2.3	16,982 GAS	1,252 MCF	1.00	1,252	6,404	8.69
6 BARTOWCC	1	1279	472,823	51.3	76.42	54.9	7,504 GAS	3,547,864 MCF	1.00	3,547,864	18,147,796	3.84
7 CITRUS CC	1-2	1640	1,044,942	88.5	91.55	96.5	6,614 GAS	6,910,830 MCF	1.00	6,910,830	35,349,816	3.38
8 DEBARY	1-10	785	577	0.3	80.90	9.4	13,317 GAS	7,687 MCF	1.00	7,687	39,321	6.81
9 H NES	1-4	2,204	463,956	29.4	61.91	63.9	7,219 GAS	3,349,207 MCF	1.00	3,349,207	17,131,641	3.69
10 INT CITY	1-14	1,186	1,828	0.2	79.29	6.4	13,185 GAS	24,101 MCF	1.00	24,101	123,273	6.74
11 OSPREY	1	505	12,368	3.4	16.16	102.0	7,999 GAS	98,929 MCF	1.00	98,929	506,033	4.09
12 SUWANNEE CT	1-3	200	714	0.6	14.41	30.7	12,571 GAS	8,980 MCF	1.00	8,980	45,935	6.43
13 TIGER BAY	1	225	48,017	29.6	90.33	96.1	7,415 GAS	356,024 MCF	1.00	356,024	1,821,109	3.79
14 UNIV OF FLA.	1	47	22,200	65.6	60.70	106.4	9,400 GAS	208,688 MCF	1.00	208,688	1,088,334	4.90
15 BARTOW	1-4	228	215	0.2	90.25	12.6	16,751 LIGHT OIL	618 BBLS	5.82	3,596	57,086	26.59
16 BARTOW CC	1	1,279	0	51.3	76.42	54.9	0 LIGHT OIL	0 BBLS	5.82	0	46,240	0.00
17 BAYBORO	1-4	231	203	0.1	93.08	22.0	13,394 LIGHT OIL	467 BBLS	5.82	2,723	45,875	22.57
18 DEBARY	1-10	785	905	0.3	80.90	9.4	13,405 LIGHT OIL	2,083 BBLS	5.82	12,135	245,773	27.15
19 H NESCC	1-4	2,204	2,763	29.4	61.91	63.9	7,207 LIGHT OIL	3,419 BBLS	5.82	19,916	302,229	10.94
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	79.29	0.0	0 LIGHT OIL	0 BBLS	5.82	0	5,292	0.00
22 SUWANNEE CT	1-3	200	146	0.6	14.41	73.2	12,766 LIGHT OIL	321 BBLS	5.82	1,868	30,518	20.86
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT OIL	1,282 BBLS	5.82	7,470	132,143	0.00
24 SOLAR	1	888	220,368	34.5	0.00	31.7	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			2,960,391							21,532,289	94,776,397	3.20

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: May-22

(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	395,884	72.7	92.58	78.5	10,324 COAL	178,314 TONS	22.92	4,087,302	11,073,737	2.80
2 CRYSTAL RIVER	5	712	347,727	65.6	92.90	70.8	10,330 COAL	156,712 TONS	22.92	3,592,153	9,810,394	2.82
3 ANCLOTE	1	517	88,683	23.1	91.61	25.2	11,394 GAS	1,010,438 MCF	1.00	1,010,438	3,987,072	4.50
4 ANCLOTE	2	521	1,084	0.3	98.06	34.7	12,045 GAS	13,059 MCF	1.00	13,059	932,098	85.97
5 BARTOW	1-4	1,279	267	0.0	91.37	2.6	14,442 GAS	3,858 MCF	1.00	3,858	18,542	6.94
6 BARTOWCC	1	1279	552,186	58.0	79.60	62.3	7,374 GAS	4,072,027 MCF	1.00	4,072,027	19,571,127	3.54
7 CITRUS CC	1-2	1640	632,859	51.9	48.84	96.2	6,536 GAS	4,136,119 MCF	1.00	4,136,119	19,879,169	3.14
8 DEBARY	1-10	785	3,921	0.8	80.77	9.2	12,849 GAS	50,382 MCF	1.00	50,382	242,148	6.18
9 HINES	1-4	2,204	1,072,708	65.6	90.98	76.3	7,235 GAS	7,761,082 MCF	1.00	7,761,082	37,301,600	3.48
10 NT CITY	1-14	1,186	5,820	0.7	78.48	6.4	12,854 GAS	74,805 MCF	1.00	74,805	359,531	6.18
11 OSPREY	1	505	124,972	33.3	97.73	95.9	7,852 GAS	981,342 MCF	1.00	981,342	4,716,562	3.77
12 SUWANNEE CT	1-3	200	935	0.7	87.10	24.2	13,523 GAS	12,646 MCF	1.00	12,646	60,778	6.50
13 TIGER BAY	1	225	66,266	39.6	89.68	85.6	7,573 GAS	501,840 MCF	1.00	501,840	2,411,964	3.64
14 UNIV OF FLA.	1	47	31,046	88.8	94.84	93.6	9,375 GAS	291,054 MCF	1.00	291,054	1,427,981	4.60
15 BARTOW	1-4	228	195	0.3	91.37	14.5	16,095 LIGHT O L	539 BBLS	5.83	3,141	50,094	25.67
16 BARTOW CC	1	1,279	0	58.0	79.60	62.3	0 LIGHT O L	0 BBLS	5.83	0	46,240	0.00
17 BAYBORO	1-4	231	158	0.1	92.66	17.1	13,841 LIGHT O L	377 BBLS	5.83	2,191	37,244	23.53
18 DEBARY	1-10	785	755	0.8	80.77	9.2	13,250 LIGHT O L	1,718 BBLS	5.83	10,002	203,965	27.02
19 HINESCC	1-4	2,204	2,545	65.6	90.98	76.3	7,145 LIGHT O L	3,121 BBLS	5.83	18,185	277,358	10.90
20 OTHER		0	0	0.0	0.00	0.0	0 LIGHT O L	0 BBLS	5.83	0	0	0.00
21 NT CITY	1-14	1,186	12	0.7	78.48	0.0	15,083 LIGHT O L	31 BBLS	5.83	181	8,255	68.79
22 SUWANNEE CT	1-3	200	129	0.7	87.10	64.4	13,455 LIGHT O L	298 BBLS	5.83	1,732	28,369	22.04
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT O L	998 BBLS	5.83	5,810	102,694	0.00
24 SOLAR	1	888	236,866	35.9	0.00	33.1	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			3,565,019							26,629,349	112,546,922	3.16

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jun-22

(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	372,101	70.6	89.00	79.3	10,319 COAL	168,318 TONS	22.81	3,839,558	10,530,690	2.83
2 CRYSTAL RIVER	5	712	337,813	65.9	91.67	72.8	10,313 COAL	152,719 TONS	22.81	3,483,733	9,614,483	2.85
3 ANCLOTE	1	517	84,060	22.6	96.77	23.6	11,487 GAS	965,630 MCF	1.00	965,630	3,753,155	4.46
4 ANCLOTE	2	521	5,292	1.4	93.87	26.0	12,389 GAS	65,564 MCF	1.00	65,564	960,248	18.14
5 BARTOW	1-4	1,279	157	0.0	90.17	2.6	14,312 GAS	2,245 MCF	1.00	2,245	10,265	6.54
6 BARTOWCC	1	1279	618,406	67.2	97.00	69.3	7,373 GAS	4,559,340 MCF	1.00	4,559,340	20,839,923	3.37
7 CITRUS CC	1-2	1640	1,076,157	91.1	94.00	96.9	6,515 GAS	7,010,650 MCF	1.00	7,010,650	32,044,419	2.98
8 DEBARY	1-10	785	1,667	0.4	81.23	8.9	12,886 GAS	21,480 MCF	1.00	21,480	98,181	5.89
9 HINES	1-4	2,204	1,032,866	65.2	95.42	75.6	7,244 GAS	7,482,576 MCF	1.00	7,482,576	34,201,509	3.31
10 INT CITY	1-14	1,186	4,232	0.7	81.71	5.9	12,984 GAS	54,951 MCF	1.00	54,951	251,171	5.93
11 OSPREY	1	505	116,469	32.0	95.57	97.3	7,836 GAS	912,690 MCF	1.00	912,690	4,171,742	3.58
12 SUWANNEE CT	1-3	200	1,396	1.1	86.17	23.7	13,656 GAS	19,067 MCF	1.00	19,067	87,152	6.24
13 TIGER BAY	1	225	58,555	36.1	92.67	85.6	7,545 GAS	441,815 MCF	1.00	441,815	2,019,458	3.45
14 UNIV OF FLA.	1	47	30,307	89.6	95.67	93.6	9,372 GAS	284,039 MCF	1.00	284,039	1,326,696	4.38
15 BARTOW	1-4	228	180	0.2	90.17	14.8	15,888 LIGHT O L	491 BBLS	5.83	2,862	45,792	25.42
16 BARTOW CC	1	1,279	0	67.2	97.00	69.3	0 LIGHT O L	0 BBLS	5.83	0	46,240	0.00
17 BAYBORO	1-4	231	167	0.1	93.59	18.0	13,845 LIGHT O L	397 BBLS	5.83	2,308	39,088	23.45
18 DEBARY	1-10	785	782	0.4	81.23	8.9	13,280 LIGHT O L	1,783 BBLS	5.83	10,382	211,426	27.04
19 HINESCC	1-4	2,204	2,555	65.2	95.42	75.6	7,149 LIGHT O L	3,135 BBLS	5.83	18,266	278,764	10.91
20 OTHER		0	0	0.0	0.00	0.0	0 LIGHT O L	0 BBLS	5.83	0	0	0.00
21 INT CITY	1-14	1,186	1,324	0.7	81.71	5.9	12,985 LIGHT O L	2,951 BBLS	5.83	17,196	285,354	21.55
22 SUWANNEE CT	1-3	200	123	1.1	86.17	61.5	13,568 LIGHT O L	286 BBLS	5.83	1,668	27,328	22.23
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT O L	1,425 BBLS	5.83	8,300	142,245	0.00
24 SOLAR	1	888	209,546	32.8	0.00	29.8	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			3,954,156							29,204,320	120,985,329	3.06

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-22

Docket No. 20210001-EI
Schedule E4
Exhibit CAM-3, Part 2
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(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	394,120	72.4	86.45	83.7	10,269 COAL	177,985 TONS	22.74	4,047,059	11,054,102	2.80
2 CRYSTAL RIVER	5	712	391,693	73.9	95.81	77.6	10,276 COAL	177,015 TONS	22.74	4,025,007	10,997,392	2.81
3 ANCLOTE	1	517	21,258	5.5	94.67	31.9	11,132 GAS	236,642 MCF	1.00	236,642	1,727,815	8.13
4 ANCLOTE	2	521	93,796	24.2	89.33	24.4	12,411 GAS	1,164,135 MCF	1.00	1,164,135	4,653,129	4.96
5 BARTOW	1-4	1,279	189	0.0	89.60	2.7	14,179 GAS	2,675 MCF	1.00	2,675	12,186	6.46
6 BARTOWCC	1	1279	638,665	67.1	96.13	69.8	7,377 GAS	4,711,505 MCF	1.00	4,711,505	21,462,272	3.36
7 CITRUS CC	1-2	1640	1,113,164	91.2	93.87	97.1	6,516 GAS	7,253,788 MCF	1.00	7,253,788	33,043,108	2.97
8 DEBARY	1-10	785	2,593	0.6	80.65	9.0	12,793 GAS	33,177 MCF	1.00	33,177	151,129	5.83
9 HINES	1-4	2,204	1,118,117	68.3	95.00	75.5	7,252 GAS	8,108,261 MCF	1.00	8,108,261	36,935,480	3.30
10 NT CITY	1-14	1,186	3,713	0.4	93.09	6.4	12,813 GAS	47,574 MCF	1.00	47,574	216,715	5.84
11 OSPREY	1	505	134,826	35.9	96.20	94.3	7,825 GAS	1,054,967 MCF	1.00	1,054,967	4,805,682	3.56
12 SUWANNEE CT	1-3	200	909	0.7	82.26	23.4	13,706 GAS	12,453 MCF	1.00	12,453	56,725	6.24
13 TIGER BAY	1	225	72,915	43.6	91.61	85.7	7,564 GAS	551,557 MCF	1.00	551,557	2,512,503	3.45
14 UNIV OF FLA.	1	47	30,096	86.1	91.94	93.6	9,385 GAS	282,453 MCF	1.00	282,453	1,314,900	4.37
15 BARTOW	1-4	228	191	0.2	89.60	15.1	15,977 LIGHT O L	524 BBLS	5.82	3,049	48,581	25.46
16 BARTOW CC	1	1,279	0	67.1	96.13	69.8	0 LIGHT O L	0 BBLS	5.82	0	46,240	0.00
17 BAYBORO	1-4	231	162	0.1	93.39	17.6	13,849 LIGHT O L	387 BBLS	5.82	2,249	38,091	23.46
18 DEBARY	1-10	785	804	0.6	80.65	9.0	13,249 LIGHT O L	1,830 BBLS	5.82	10,653	216,766	26.96
19 HINESCC	1-4	2,204	2,555	68.3	95.00	75.5	7,148 LIGHT O L	3,135 BBLS	5.82	18,266	279,004	10.92
20 OTHER		0	0	0.0	0.00	0.0	0 LIGHT O L	0 BBLS	5.82	0	0	0.00
21 NT CITY	1-14	1,186	30	0.4	93.09	6.4	14,933 LIGHT O L	77 BBLS	5.82	448	12,594	41.98
22 SUWANNEE CT	1-3	200	123	0.7	82.26	61.4	13,593 LIGHT O L	287 BBLS	5.82	1,668	27,312	22.26
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT O L	1,353 BBLS	5.82	7,885	133,706	0.00
24 SOLAR	1	888	208,617	31.6	0.00	28.3	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			4,228,536							31,575,471	129,745,432	3.07

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-22

(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	424,045	77.9	93.55	83.8	10,269 COAL	191,878 TONS	22.69	4,354,406	12,011,214	2.83
2 CRYSTAL RIVER	5	712	382,503	72.2	94.19	76.6	10,280 COAL	173,273 TONS	22.69	3,932,180	10,909,276	2.85
3 ANCLOTE	1	517	63,802	16.6	94.52	24.6	11,482 GAS	732,566 MCF	1.00	732,566	3,549,681	5.56
4 ANCLOTE	2	521	82,276	21.2	97.74	21.8	12,682 GAS	1,043,419 MCF	1.00	1,043,419	4,532,596	5.51
5 BARTOW	1-4	1,279	329	0.1	89.52	2.8	14,219 GAS	4,681 MCF	1.00	4,681	21,300	6.47
6 BARTOWCC	1	1279	606,417	63.7	92.90	68.6	7,383 GAS	4,477,230 MCF	1.00	4,477,230	20,375,297	3.36
7 CITRUS CC	1-2	1640	1,112,333	91.2	93.88	97.0	6,515 GAS	7,246,567 MCF	1.00	7,246,567	32,978,191	2.96
8 DEBARY	1-10	785	6,424	1.2	80.42	9.3	12,856 GAS	82,589 MCF	1.00	82,589	375,854	5.85
9 H NES	1-4	2,204	1,119,703	68.5	95.65	73.3	7,277 GAS	8,148,538 MCF	1.00	8,148,538	37,082,940	3.31
10 INT CITY	1-14	1,186	8,595	1.0	92.77	6.3	12,862 GAS	110,546 MCF	1.00	110,546	503,084	5.85
11 OSPREY	1	505	134,499	35.8	97.00	97.2	7,829 GAS	1,052,964 MCF	1.00	1,052,964	4,791,901	3.56
12 SUWANNEE CT	1-3	200	2,514	1.7	82.26	24.1	13,622 GAS	34,244 MCF	1.00	34,244	155,838	6.20
13 TIGER BAY	1	225	77,856	46.5	92.26	85.9	7,575 GAS	589,789 MCF	1.00	589,789	2,684,052	3.45
14 UNIV OF FLA.	1	47	31,258	89.4	95.48	93.7	9,373 GAS	292,966 MCF	1.00	292,966	1,362,545	4.36
15 BARTOW	1-4	228	201	0.3	89.52	15.5	16,016 LIGHT OIL	554 BBLS	5.82	3,227	51,230	25.43
16 BARTOW CC	1	1,279	0	63.7	92.90	68.6	0 LIGHT OIL	0 BBLS	5.82	0	46,240	0.00
17 BAYBORO	1-4	231	169	0.1	92.90	18.3	13,898 LIGHT OIL	404 BBLS	5.82	2,346	39,614	23.47
18 DEBARY	1-10	785	728	1.2	80.42	9.3	13,307 LIGHT OIL	1,665 BBLS	5.82	9,692	197,890	27.17
19 H NESCC	1-4	2,204	2,727	68.5	95.65	73.3	7,156 LIGHT OIL	3,349 BBLS	5.82	19,513	297,425	10.91
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	87	1.0	92.77	6.3	14,554 LIGHT OIL	219 BBLS	5.82	1,272	26,011	29.76
22 SUWANNEE CT	1-3	200	90	1.7	82.26	44.8	13,474 LIGHT OIL	207 BBLS	5.82	1,206	20,079	22.43
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT OIL	854 BBLS	5.82	4,980	85,776	0.00
24 SOLAR	1	888	197,975	30.0	0.00	27.7	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			4,254,529							32,144,921	132,098,034	3.10

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-22

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVA L 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	377,924	71.7	88.67	82.2	10,285 COAL	171,482 TONS	22.67	3,886,854	10,848,744	2.87
2 CRYSTAL RIVER	5	712	346,179	67.5	89.67	75.3	10,291 COAL	157,178 TONS	22.67	3,562,632	9,997,571	2.89
3 ANCLOTE	1	517	32,060	8.6	94.67	29.5	11,206 GAS	359,250 MCF	1.00	359,250	2,131,252	6.65
4 ANCLOTE	2	521	81,558	21.7	92.33	23.1	12,533 GAS	1,022,185 MCF	1.00	1,022,185	4,213,531	5.17
5 BARTOW	1-4	1,279	151	0.0	90.17	2.6	14,287 GAS	2,163 MCF	1.00	2,163	9,933	6.56
6 BARTOWCC	1	1279	602,340	65.4	95.67	68.4	7,377 GAS	4,443,662 MCF	1.00	4,443,662	20,409,253	3.39
7 CITRUS CC	1-2	1640	1,068,464	90.5	93.33	96.9	6,517 GAS	6,963,021 MCF	1.00	6,963,021	31,980,394	2.99
8 DEBARY	1-10	785	2,935	0.7	80.37	8.7	12,918 GAS	37,913 MCF	1.00	37,913	174,127	5.93
9 H NES	1-4	2,204	1,041,913	65.8	94.00	72.1	7,275 GAS	7,579,868 MCF	1.00	7,579,868	34,813,500	3.34
10 INT CITY	1-14	1,186	6,534	0.9	92.33	6.1	12,936 GAS	84,520 MCF	1.00	84,520	388,199	5.94
11 OSPREY	1	505	79,901	22.0	50.11	98.3	7,791 GAS	622,529 MCF	1.00	622,529	2,859,207	3.58
12 SUWANNEE CT	1-3	200	1,282	1.0	82.00	23.3	13,651 GAS	17,496 MCF	1.00	17,496	80,358	6.27
13 TIGER BAY	1	225	62,841	38.8	90.00	85.7	7,551 GAS	474,524 MCF	1.00	474,524	2,179,438	3.47
14 UNIV OF FLA.	1	47	30,307	89.6	95.67	93.6	9,372 GAS	284,039 MCF	1.00	284,039	1,332,965	4.40
15 BARTOW	1-4	228	187	0.2	90.17	14.8	15,941 LIGHT OIL	513 BBLS	5.81	2,981	47,439	25.37
16 BARTOW CC	1	1,279	0	65.4	95.67	68.4	0 LIGHT OIL	0 BBLS	5.81	0	46,240	0.00
17 BAYBORO	1-4	231	163	0.1	93.00	17.6	13,840 LIGHT OIL	386 BBLS	5.81	2,249	38,028	23.40
18 DEBARY	1-10	785	742	0.7	80.37	8.7	13,303 LIGHT OIL	1,696 BBLS	5.81	9,875	201,511	27.15
19 H NESCC	1-4	2,204	2,638	65.8	94.00	72.1	7,159 LIGHT OIL	3,242 BBLS	5.81	18,889	288,550	10.94
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	1,434	0.9	92.33	6.1	12,979 LIGHT OIL	3,194 BBLS	5.81	18,606	306,567	21.39
22 SUWANNEE CT	1-3	200	114	1.0	82.00	56.9	13,537 LIGHT OIL	265 BBLS	5.81	1,540	25,298	22.24
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT OIL	1,496 BBLS	5.81	8,715	144,564	0.00
24 SOLAR	1	888	180,242	28.2	0.00	26.7	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			3,919,908							29,403,511	122,516,669	3.13

Duke Energy Florida, LLC
System Net Generation and Fuel Cost

Estimated for the Period of: Oct-22

(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	381,533	70.1	88.39	81.1	10,299 COAL	173,490 TONS	22.65	3,929,299	10,999,299	2.88
2 CRYSTAL RIVER	5	712	314,435	59.4	79.61	74.1	10,299 COAL	142,989 TONS	22.65	3,238,509	9,179,394	2.92
3 ANCLOTE	1	517	32,972	8.6	92.58	28.1	11,341 GAS	373,924 MCF	1.00	373,924	2,116,165	6.42
4 ANCLOTE	2	521	64,345	16.6	94.19	24.8	12,419 GAS	799,126 MCF	1.00	799,126	3,447,898	5.36
5 BARTOW	1-4	1,279	216	0.0	89.92	2.7	14,154 GAS	3,063 MCF	1.00	3,063	14,527	6.71
6 BARTOWCC	1	1279	567,934	59.7	90.54	62.2	7,504 GAS	4,262,034 MCF	1.00	4,262,034	20,215,856	3.56
7 CITRUS CC	1-2	1640	1,084,832	88.9	92.26	94.0	6,520 GAS	7,073,298 MCF	1.00	7,073,298	33,550,364	3.09
8 DEBARY	1-10	785	2,810	0.6	72.45	8.5	13,005 GAS	36,540 MCF	1.00	36,540	173,317	6.17
9 HINES	1-4	2,204	663,489	40.6	71.53	69.1	7,363 GAS	4,885,153 MCF	1.00	4,885,153	23,171,468	3.49
10 INT CITY	1-14	1,186	4,238	0.5	92.86	6.1	13,040 GAS	55,268 MCF	1.00	55,268	262,153	6.19
11 OSPREY	1	505	47,685	12.7	44.41	88.2	7,900 GAS	376,723 MCF	1.00	376,723	1,786,888	3.75
12 SUWANNEE CT	1-3	200	805	0.6	84.84	21.6	14,246 GAS	11,461 MCF	1.00	11,461	54,362	6.76
13 TIGER BAY	1	225	49,954	29.8	88.71	85.7	7,594 GAS	379,335 MCF	1.00	379,335	1,799,278	3.60
14 UNIV OF FLA.	1	47	14,256	40.8	41.59	93.6	9,388 GAS	133,831 MCF	1.00	133,831	648,176	4.55
15 BARTOW	1-4	228	195	0.2	89.92	15.1	16,098 LIGHT OIL	540 BBLS	5.83	3,147	49,901	25.53
16 BARTOW CC	1	1,279	0	59.7	90.54	62.2	0 LIGHT OIL	0 BBLS	5.83	0	46,240	0.00
17 BAYBORO	1-4	231	162	0.1	93.15	17.6	13,849 LIGHT OIL	387 BBLS	5.83	2,249	37,974	23.38
18 DEBARY	1-10	785	714	0.6	72.45	8.5	13,434 LIGHT OIL	1,648 BBLS	5.83	9,593	195,955	27.44
19 HINESCC	1-4	2,204	1,641	40.6	71.53	69.1	7,222 LIGHT OIL	2,034 BBLS	5.83	11,850	185,902	11.33
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	0	0.0	92.86	0.0	0 LIGHT OIL	0 BBLS	5.83	0	5,292	0.00
22 SUWANNEE CT	1-3	200	101	0.6	84.84	50.6	13,923 LIGHT OIL	243 BBLS	5.83	1,410	23,246	22.95
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT OIL	1,496 BBLS	5.83	8,715	143,171	0.00
24 SOLAR	1	888	174,496	26.4	0.00	27.0	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			3,406,814							25,594,528	108,106,826	3.17

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-22

(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	395,298	75.0	94.00	81.0	10,068 COAL	175,853 TONS	22.63	3,979,934	11,196,486	2.83
2 CRYSTAL RIVER	5	712	0	0.0	0.00	0.0	0 COAL	0 TONS	0.00	0	638,643	0.00
3 ANCLOTE	1	517	33,898	9.1	96.67	19.9	11,764 GAS	398,776 MCF	1.00	398,776	1,888,694	5.57
4 ANCLOTE	2	521	25,693	6.8	96.67	26.8	11,697 GAS	300,533 MCF	1.00	300,533	1,574,317	6.13
5 BARTOW	1-4	1,279	242	0.1	46.37	3.1	13,690 GAS	3,316 MCF	1.00	3,316	16,422	6.78
6 BARTOWCC	1	1279	223,391	24.3	46.36	25.5	10,242 GAS	2,287,897 MCF	1.00	2,287,897	11,329,766	5.07
7 CITRUS CC	1-2	1640	898,823	76.1	70.17	82.2	6,510 GAS	5,851,560 MCF	1.00	5,851,560	28,977,185	3.22
8 DEBARY	1-10	785	1,433	0.4	66.20	9.9	12,506 GAS	17,922 MCF	1.00	17,922	88,747	6.19
9 HINES	1-4	2,204	801,639	50.6	73.04	82.8	7,073 GAS	5,670,089 MCF	1.00	5,670,089	28,078,532	3.50
10 NT CITY	1-14	1,186	4,778	0.6	86.49	6.6	12,819 GAS	61,243 MCF	1.00	61,243	303,274	6.35
11 OSPREY	1	505	113,011	31.1	96.32	83.8	7,721 GAS	872,569 MCF	1.00	872,569	4,321,001	3.82
12 SUWANNEE CT	1-3	200	2,471	1.8	64.71	28.4	12,830 GAS	31,706 MCF	1.00	31,706	157,011	6.35
13 TIGER BAY	1	225	66,684	41.2	91.67	96.9	7,480 GAS	498,808 MCF	1.00	498,808	2,470,118	3.70
14 UNIV OF FLA.	1	47	34,680	102.5	96.33	106.3	9,391 GAS	325,683 MCF	1.00	325,683	1,645,365	4.74
15 BARTOW	1-4	228	227	0.3	46.37	17.1	15,017 LIGHT O L	585 BBLS	5.82	3,407	53,765	23.70
16 BARTOW CC	1	1,279	0	24.3	46.36	25.5	0 LIGHT O L	0 BBLS	5.82	0	46,240	0.00
17 BAYBORO	1-4	231	203	0.1	93.42	22.0	13,391 LIGHT O L	467 BBLS	5.82	2,721	45,492	22.39
18 DEBARY	1-10	785	735	0.4	66.20	9.9	12,740 LIGHT O L	1,606 BBLS	5.82	9,361	191,421	26.05
19 HINESCC	1-4	2,204	898	50.6	73.04	82.8	7,125 LIGHT O L	1,099 BBLS	5.82	6,401	106,366	11.84
20 OTHER		0	0	0.0	0.00	0.0	0 LIGHT O L	0 BBLS	5.82	0	0	0.00
21 NT CITY	1-14	1,186	0	0.0	86.49	0.0	0 LIGHT O L	0 BBLS	5.82	0	5,292	0.00
22 SUWANNEE CT	1-3	200	138	1.8	64.71	68.8	12,841 LIGHT O L	303 BBLS	5.82	1,766	28,781	20.93
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT O L	356 BBLS	5.82	2,075	38,029	0.00
24 SOLAR	1	888	148,032	23.2	0.00	24.3	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			2,752,273							20,325,767	93,200,947	3.39

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-22

(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	438,503	80.5	95.81	84.4	10,026 COAL	194,326 TONS	22.62	4,396,279	12,384,077	2.82
2 CRYSTAL RIVER	5	712	99,913	18.9	17.06	82.5	9,958 COAL	43,978 TONS	22.62	994,925	3,299,782	3.30
3 ANCLOTE	1	517	5,804	1.5	91.61	14.6	12,403 GAS	71,983 MCF	1.00	71,983	401,776	6.92
4 ANCLOTE	2	521	7,463	1.9	94.52	18.8	13,312 GAS	99,354 MCF	1.00	99,354	492,950	6.60
5 BARTOW	1-4	1,279	78	0.0	82.50	2.4	16,850 GAS	1,306 MCF	1.00	1,306	6,819	8.80
6 BARTOWCC	1	1279	583,506	61.3	95.48	64.2	7,152 GAS	4,173,231 MCF	1.00	4,173,231	21,792,777	3.73
7 CITRUS CC	1-2	1640	1,078,507	88.4	89.03	94.3	6,517 GAS	7,028,395 MCF	1.00	7,028,395	36,702,557	3.40
8 DEBARY	1-10	785	1,307	0.4	74.91	9.2	13,033 GAS	17,036 MCF	1.00	17,036	88,960	6.81
9 HINES	1-4	2,204	474,274	29.1	94.55	71.9	7,061 GAS	3,348,893 MCF	1.00	3,348,893	17,488,053	3.69
10 INT CITY	1-14	1,186	2,957	0.5	93.13	5.9	13,449 GAS	39,773 MCF	1.00	39,773	207,704	7.02
11 OSPREY	1	505	57,251	15.2	95.56	77.1	7,807 GAS	446,941 MCF	1.00	446,941	2,333,945	4.08
12 SUWANNEE CT	1-3	200	3,079	2.2	85.32	24.9	13,509 GAS	41,594 MCF	1.00	41,594	217,204	7.05
13 TIGER BAY	1	225	11,771	7.0	89.03	95.1	7,528 GAS	88,613 MCF	1.00	88,613	462,743	3.93
14 UNIV OF FLA.	1	47	35,520	101.6	95.48	106.4	9,392 GAS	333,595 MCF	1.00	333,595	1,775,404	5.00
15 BARTOW	1-4	228	107	0.1	82.50	13.5	16,543 LIGHT O L	305 BBLS	5.82	1,775	29,113	27.13
16 BARTOW CC	1	1,279	0	61.3	95.48	64.2	0 LIGHT O L	0 BBLS	5.82	0	46,240	0.00
17 BAYBORO	1-4	231	192	0.1	93.15	20.8	13,385 LIGHT O L	442 BBLS	5.82	2,574	43,081	22.40
18 DEBARY	1-10	785	924	0.4	74.91	9.2	12,938 LIGHT O L	2,051 BBLS	5.82	11,954	242,241	26.22
19 HINESCC	1-4	2,204	2,635	29.1	94.55	71.9	7,140 LIGHT O L	3,229 BBLS	5.82	18,812	287,554	10.91
20 OTHER		0	0	0.0	0.00	0.0	0 LIGHT O L	0 BBLS	5.82	0	0	0.00
21 INT CITY	1-14	1,186	1,819	0.5	93.13	5.9	12,862 LIGHT O L	4,015 BBLS	5.82	23,392	381,505	20.98
22 SUWANNEE CT	1-3	200	151	2.2	85.32	75.7	13,251 LIGHT O L	344 BBLS	5.82	2,007	32,506	21.46
23 OTHER - START UP	0	-	0	-	0.00	0.0	0 LIGHT O L	1,068 BBLS	5.82	6,225	102,842	0.00
24 SOLAR	1	888	129,671	19.6	0.00	20.1	0 SOLAR	0 N/A		0	0	0.00
25 TOTAL			2,935,432							21,148,657	98,819,833	3.37

Duke Energy Florida, LLC
Inventory Analysis

Estimated for the Period of : January 2022 through December 2022

		Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Subtotal
	LIGHT OIL							
1	PURCHASES:							
2	UNITS BBL	8,090	8,940	141,549	8,190	7,082	10,468	184,319
3	UNIT COST \$/BBL	106.52	105.65	109.95	105.64	106.50	102.81	108.86
4	AMOUNT \$	861,707	944,542	15,563,088	865,156	754,219	1,076,237	20,064,949
5	BURNED:							
6	UNITS BBL	8,090	8,940	141,549	8,190	7,082	10,468	184,319
7	UNIT COST \$/BBL	106.52	105.65	109.95	105.64	106.50	102.81	108.86
8	AMOUNT \$	861,707	944,542	15,563,088	865,156	754,219	1,076,237	20,064,949
9	ENDING INVENTORY:							
10	UNITS BBL	431,972	431,972	431,972	431,972	431,972	431,972	
11	UNIT COST \$/BBL	109.46	109.46	109.46	109.46	109.46	109.46	
12	AMOUNT \$	47,283,848	47,283,848	47,283,848	47,283,848	47,283,848	47,283,848	
	COAL							
13	PURCHASES:							
14	UNITS TON	238,922	233,813	344,184	290,707	335,026	321,037	1,763,689
15	UNIT COST \$/TON	64.74	64.72	62.94	63.12	62.34	62.75	63.30
16	AMOUNT \$	15,467,529	15,133,404	21,664,435	18,349,980	20,884,131	20,145,173	111,644,652
17	BURNED:							
18	UNITS TON	238,922	233,813	344,184	290,707	335,026	321,037	1,763,689
19	UNIT COST \$/TON	64.74	64.72	62.94	63.12	62.34	62.75	63.30
20	AMOUNT \$	15,467,529	15,133,404	21,664,435	18,349,980	20,884,131	20,145,173	111,644,652
21	ENDING INVENTORY:							
22	UNITS TON	351,644	351,644	351,644	351,644	351,644	351,644	
23	UNIT COST \$/TON	63.96	63.96	63.96	63.96	63.96	63.96	
24	AMOUNT \$	22,490,179	22,490,179	22,490,179	22,490,179	22,490,179	22,490,179	
	GAS							
25	BURNED:							
26	UNITS MCF	16,219,211	13,899,572	12,828,623	14,768,022	18,908,652	21,820,047	98,444,127
27	UNIT COST \$/MCF	6.01	6.02	6.12	5.12	4.81	4.57	5.34
28	AMOUNT \$	97,470,551	83,726,171	78,495,150	75,561,261	90,908,572	99,763,919	525,925,624

Duke Energy Florida, LLC
Inventory Analysis

Estimated for the Period of : January 2022 through December 2022

			Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	7,593	7,252	10,792	6,348	4,416	11,454	232,174
3	UNIT COST	\$/BBL	105.66	105.39	101.76	108.33	116.71	101.72	108.10
4	AMOUNT	\$	802,294	764,265	1,098,197	687,681	515,386	1,165,082	25,097,854
5	BURNED:								
6	UNITS	BBL	7,593	7,252	10,792	6,348	4,416	11,454	232,174
7	UNIT COST	\$/BBL	105.66	105.39	101.76	108.33	116.71	101.72	108.10
8	AMOUNT	\$	802,294	764,265	1,098,197	687,681	515,386	1,165,082	25,097,854
9	ENDING INVENTORY:								
10	UNITS	BBL	431,972	431,972	431,972	431,972	431,972	431,972	
11	UNIT COST	\$/BBL	109.46	109.46	109.46	109.46	109.46	109.46	
12	AMOUNT	\$	47,283,848	47,283,848	47,283,848	47,283,848	47,283,848	47,283,848	
	COAL								
13	PURCHASES:								
14	UNITS	TON	355,000	365,151	328,660	316,479	175,853	238,304	3,543,136
15	UNIT COST	\$/TON	62.12	62.77	63.43	63.76	67.30	65.81	63.55
16	AMOUNT	\$	22,051,494	22,920,490	20,846,315	20,178,693	11,835,129	15,683,859	225,160,632
17	BURNED:								
18	UNITS	TON	355,000	365,151	328,660	316,479	175,853	238,304	3,543,136
19	UNIT COST	\$/TON	62.12	62.77	63.43	63.76	67.30	65.81	63.55
20	AMOUNT	\$	22,051,494	22,920,490	20,846,315	20,178,693	11,835,129	15,683,859	225,160,632
21	ENDING INVENTORY:								
22	UNITS	TON	351,644	351,644	351,644	351,644	351,644	351,644	
23	UNIT COST	\$/TON	63.96	63.96	63.96	63.96	63.96	63.96	
24	AMOUNT	\$	22,490,179	22,490,179	22,490,179	22,490,179	22,490,179	22,490,179	
	GAS								
25	BURNED:								
26	UNITS	MCF	23,459,187	23,816,099	21,891,170	18,389,756	16,320,102	15,690,714	218,011,155
27	UNIT COST	\$/MCF	4.56	4.55	4.59	4.74	4.95	5.22	5.01
28	AMOUNT	\$	106,891,644	108,413,279	100,572,157	87,240,452	80,850,432	81,970,892	1,091,864,480

Duke Energy Florida, LLC
 Fuel Cost of Power Sold
 Estimated for the Period of : January 2022 through December 2022

(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		(8) TOTAL \$ FOR FUEL ADJ (6) x (7)(A)	(9) TOTAL COST \$ (6) x (7)(B)	(10) REFUNDABLE GAIN ON POWER SALES \$
						(A) FUEL COST	(B) TOTAL COST			
Jan-22	ECONSALE	--	43,860		43,860	4.024	5.114	1,764,766	2,243,052	478,286
	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	--	63,124		63,124	3.869	3.869	2,442,070	2,442,070	0
	TOTAL		106,984		106,984	3.932	4.379	4,206,836	4,685,122	478,286
Feb-22	ECONSALE	--	30,303		30,303	3.716	4.723	1,125,987	1,431,152	305,165
	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	--	61,850		61,850	4.023	4.023	2,487,936	2,487,936	0
	TOTAL		92,153		92,153	3.922	4.253	3,613,923	3,919,088	305,165
Mar-22	ECONSALE	--	30,994		30,994	3.324	4.225	1,030,356	1,309,603	279,247
	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	--	138,006		138,006	3.198	3.198	4,413,999	4,413,999	0
	TOTAL		169,001		169,001	3.222	3.387	5,444,355	5,723,602	279,247
Apr-22	ECONSALE	--	14,750		14,750	3.335	4.239	491,906	625,223	133,317
	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	--	78,887		78,887	2.751	2.751	2,170,530	2,170,530	0
	TOTAL		93,637		93,637	2.843	2.986	2,662,436	2,795,753	133,317
May-22	ECONSALE	--	15,314		15,314	3.787	4.813	579,943	737,119	157,176
	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	--	91,001		91,001	2.669	2.669	2,428,864	2,428,864	0
	TOTAL		106,316		106,316	2.830	2.978	3,008,807	3,165,983	157,176
Jun-22	ECONSALE	--	14,812		14,812	3.758	4.776	556,596	707,444	150,848
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(19,193)	(19,193)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	133,727		133,727	2.568	2.568	3,434,300	3,434,300	0
	TOTAL		148,539		148,539	2.687	2.775	3,990,896	4,122,551	131,655
Jan THRU Jun-22	ECONSALE	--	150,035		150,035	3.699	4.701	5,549,554	7,053,593	1,504,039
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(19,193)	(19,193)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	566,595		566,595	3067.042	3067.042	17,377,699	17,377,699	0
	TOTAL		716,629		716,629	3.199	3.407	22,927,253	24,412,099	1,484,846

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2022 through December 2022

(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		TOTAL \$ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST \$ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES \$
						(A) FUEL COST	(B) TOTAL COST			
Jul-22	ECONSALE	--	12,890		12,890	3.768	4.789	485,703	617,339	131,636
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(26,327)	(26,327)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	202,176		202,176	2.540	2.540	5,134,465	5,134,465	0
	TOTAL		215,066		215,066	2.613	2.662	5,620,168	5,725,477	105,309
Aug-22	ECONSALE	--	19,837		19,837	3.798	4.827	753,366	957,543	204,177
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(40,835)	(40,835)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	188,891		188,891	2.559	2.559	4,834,350	4,834,350	0
	TOTAL		208,727		208,727	2.677	2.755	5,587,716	5,751,058	163,342
Sep-22	ECONSALE	--	19,184		19,184	3.554	4.518	681,863	866,661	184,798
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(36,960)	(36,960)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	145,380		145,380	2.586	2.586	3,759,657	3,759,657	0
	TOTAL		164,564		164,564	2.699	2.789	4,441,520	4,589,359	147,838
Oct-22	ECONSALE	--	17,806		17,806	3.338	4.243	594,342	755,420	161,078
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(32,216)	(32,216)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	139,749		139,749	2.618	2.618	3,658,545	3,658,545	0
	TOTAL		157,555		157,555	2.699	2.781	4,252,887	4,381,749	128,862
Nov-22	ECONSALE	--	13,968		13,968	3.458	4.396	483,073	613,995	130,922
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(26,184)	(26,184)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	78,670		78,670	2.758	2.758	2,169,559	2,169,559	0
	TOTAL		92,638		92,638	2.863	2.977	2,652,632	2,757,370	104,738
Dec-22	ECONSALE	--	18,112		18,112	2.939	3.736	532,355	676,633	144,278
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(28,856)	(28,856)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	89,861		89,861	3.064	3.064	2,753,466	2,753,466	0
	TOTAL		107,973		107,973	3.043	3.150	3,285,821	3,401,243	115,422
Jan-22	ECONSALE	--	251,831		251,831	3.606	4.583	9,080,256	11,541,184	2,460,928
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-22	EXCESS GAIN	--	0		0	0.000	0.000	0	(210,570)	(210,570)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,411,321		1,411,321	2.812	2.812	39,687,742	39,687,742	0
	TOTAL		1,663,152		1,663,152	2.932	3.068	48,767,998	51,018,355	2,250,358

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2022 through December 2022

(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 FIRM	(8) C/KWH		(9) TOTAL \$ FOR FUEL ADJ (7) x (8)(B)
							(A) FUEL COST	(B) TOTAL COST	
Jan-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	1,114			1,114	7.651	7.651	85,201
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	3,412			3,412	9.310	9.310	317,658
	TOTAL		4,526	0	0	4,526	8.902	8.902	402,859
Feb-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	0			0	0.000	0.000	2,076
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	404			404	18.198	18.198	73,485
	TOTAL		404	0	0	404	18.712	18.712	75,561
Mar-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	935			935	7.666	7.666	71,658
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	1,170			1,170	11.069	11.069	129,467
	TOTAL		2,104	0	0	2,104	9.558	9.558	201,125
Apr-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	563			563	6.099	6.099	34,334
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	6,687			6,687	6.954	6.954	465,022
	TOTAL		7,250	0	0	7,250	6.887	6.887	499,356
May-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	3,981			3,981	10.224	10.224	406,997
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	17,416			17,416	7.794	7.794	1,357,385
	TOTAL		21,396	0	0	21,396	8.246	8.246	1,764,382
Jun-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	5,531			5,531	5.286	5.286	292,399
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	15,995			15,995	6.102	6.102	976,036
	TOTAL		21,527	0	0	21,527	5.892	5.892	1,268,435
Jan-22	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	12,124			12,124	7.363	7.363	892,665
Jun-22	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	45,083			45,083	7.362	7.362	3,319,053
	TOTAL		57,207	0	0	57,207	7.362	7.362	4,211,718

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2022 through December 2022

(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 FIRM	(8) C/KWH		(9) TOTAL \$ FOR FUEL ADJ (7) x (8)(B)
							(A) FUEL COST	(B) TOTAL COST	
Jul-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	7,425			7,425	5.249	5.249	389,727
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	24,610			24,610	5.867	5.867	1,443,881
	TOTAL		32,035	0	0	32,035	5.724	5.724	1,833,608
Aug-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	5,216			5,216	5.259	5.259	274,329
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	13,187			13,187	6.299	6.299	830,671
	TOTAL		18,403	0	0	18,403	6.005	6.005	1,105,000
Sep-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	2,926			2,926	5.295	5.295	154,914
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	22,925			22,925	6.091	6.091	1,396,382
	TOTAL		25,850	0	0	25,850	6.001	6.001	1,551,296
Oct-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	2,619			2,619	5.569	5.569	145,845
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	18,757			18,757	6.190	6.190	1,161,019
	TOTAL		21,376	0	0	21,376	6.114	6.114	1,306,864
Nov-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	2,040			2,040	15.167	15.167	309,429
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	9,934			9,934	8.967	8.967	890,765
	TOTAL		11,974	0	0	11,974	10.023	10.023	1,200,194
Dec-22	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	0			0	0.000	0.000	2,076
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	62			62	77.547	77.547	48,312
	TOTAL		62	0	0	62	80.880	80.880	50,388
Jan-22	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	32,349			32,349	6.705	6.705	2,168,985
Dec-22	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	134,558			134,558	6.755	6.755	9,090,083
	TOTAL		166,907	0	0	166,907	6.746	6.746	11,259,068

Duke Energy Florida, LLC
Energy Payments to Qualifying Facilities
Estimated for the Period of : January 2022 through December 2022

(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 FIRM	(8) C/KWH		(9) TOTAL \$ FOR FUEL ADJ (7) x (8)(A)
							(A) ENERGY COST	(B) TOTAL COST	
Jan-22	QUAL. FACILITIES	COGEN	237,161			237,161	4.341	17.072	10,295,502
Feb-22	QUAL. FACILITIES	COGEN	201,745			201,745	4.323	19.288	8,720,904
Mar-22	QUAL. FACILITIES	COGEN	200,628			200,628	4.431	19.479	8,889,132
Apr-22	QUAL. FACILITIES	COGEN	198,596			198,596	4.209	19.411	8,358,583
May-22	QUAL. FACILITIES	COGEN	229,907			229,907	4.293	17.426	9,871,035
Jun-22	QUAL. FACILITIES	COGEN	222,491			222,491	4.301	17.871	9,570,424
Jul-22	QUAL. FACILITIES	COGEN	229,907			229,907	4.303	17.435	9,892,305
Aug-22	QUAL. FACILITIES	COGEN	229,907			229,907	4.287	17.419	9,855,911
Sep-22	QUAL. FACILITIES	COGEN	222,491			222,491	4.291	17.860	9,546,078
Oct-22	QUAL. FACILITIES	COGEN	219,455			219,455	4.354	18.112	9,555,749
Nov-22	QUAL. FACILITIES	COGEN	226,431			226,431	4.213	17.547	9,539,620
Dec-22	QUAL. FACILITIES	COGEN	245,679			245,679	4.085	16.374	10,034,922
TOTAL	QUAL. FACILITIES	COGEN	2,664,397			2,664,397	4.284	17.881	114,130,163

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2022 through December 2022

(1) MONTH	(2) PURCHASE	(3) TYPE & SCHED	(4) TOTAL MWH PURCHASED	(5) TRANSACTION COST		(6) TOTAL \$ FOR FUEL ADJ (4) x (5)	(7) COST IF GENERATED		(8) FUEL SAVINGS (8)(B) - (7)
				ENERGY COST C/KWH	TOTAL COST C/KWH		(A) C/KWH	(B) \$	
Jan-22	ECONPURCH	--	5,569	4.589	4.589	255,518	5.245	292,047	36,529
	SEPA	--	0	0.000	0.000	0	0.000	0	-
TOTAL			5,569	4.589	4.589	255,518	5.245	292,047	36,529
Feb-22	ECONPURCH	--	5,233	4.669	4.669	244,320	5.336	279,202	34,882
	SEPA	--	0	0.000	0.000	0	0.000	0	-
TOTAL			5,233	4.669	4.669	244,320	5.336	279,202	34,882
Mar-22	ECONPURCH	--	11,081	4.480	4.480	496,365	5.119	567,249	70,884
	SEPA	--	0	0.000	0.000	0	0.000	0	-
TOTAL			11,081	4.480	4.480	496,365	5.119	567,249	70,884
Apr-22	ECONPURCH	--	3,786	4.067	4.067	153,968	4.648	175,973	22,005
	SEPA	--	0	0.000	0.000	0	0.000	0	-
TOTAL			3,786	4.067	4.067	153,968	4.648	175,973	22,005
May-22	ECONPURCH	--	4,709	4.525	4.525	213,081	5.171	243,527	30,446
	SEPA	--	0	0.000	0.000	0	0.000	0	-
TOTAL			4,709	4.525	4.525	213,081	5.171	243,527	30,446
Jun-22	ECONPURCH	--	3,323	4.904	4.904	162,977	5.603	186,225	23,248
	SEPA	--	0	0.000	0.000	0	0.000	0	-
TOTAL			3,323	4.904	4.904	162,977	5.603	186,225	23,248
Jan-22 THRU Jun-22	ECONPURCH	--	33,700	4.529	4.529	1,526,229	5.176	1,744,223	217,994
	SEPA	--	0	0.000	0.000	0	-	0	-
TOTAL			33,700	4.529	4.529	1,526,229	5.176	1,744,223	217,994

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2022 through December 2022

(1) MONTH	(2) PURCHASE	(3) TYPE & SCHED	(4) TOTAL MWH PURCHASED	(5) TRANSACTION COST		(6) TOTAL \$ FOR FUEL ADJ (4) x (5)	(8) COST IF GENERATED		(9) FUEL SAVINGS (8)(B) - (7)
				ENERGY COST C/KWH	TOTAL COST C/KWH		(A) C/KWH	(B) \$	
Jul-22	ECONPURCH	--	4,835	4.688	4.688	226,632	5.357	258,988	32,356
	SEPA	--	0	0.000	0.000	0	0.000	0	-
			TOTAL	4,835	4.688	226,632	5.357	258,988	32,356
Aug-22	ECONPURCH	--	4,913	4.945	4.945	242,983	5.652	277,712	34,729
	SEPA	--	0	0.000	0.000	0	0.000	0	-
			TOTAL	4,913	4.945	242,983	5.652	277,712	34,729
Sep-22	ECONPURCH	--	5,201	4.779	4.779	248,573	5.462	284,079	35,506
	SEPA	--	0	0.000	0.000	0	0.000	0	-
			TOTAL	5,201	4.779	248,573	5.462	284,079	35,506
Oct-22	ECONPURCH	--	6,565	4.292	4.292	281,761	4.905	321,988	40,227
	SEPA	--	0	0.000	0.000	0	0.000	0	-
			TOTAL	6,565	4.292	281,761	4.905	321,988	40,227
Nov-22	ECONPURCH	--	5,629	4.007	4.007	225,562	4.580	257,804	32,242
	SEPA	--	0	0.000	0.000	0	0.000	0	-
			TOTAL	5,629	4.007	225,562	4.580	257,804	32,242
Dec-22	ECONPURCH	--	5,589	3.961	3.961	221,401	4.527	253,040	31,639
	SEPA	--	0	0.000	0.000	0	0.000	0	-
			TOTAL	5,589	3.961	221,401	4.527	253,040	31,639
Jan-22 THRU Dec-22	ECONPURCH	--	66,432	4.475	4.475	2,973,141	5.115	3,397,834	424,693
	SEPA	--	0	0.000	0.000	0	0.000	0	-
			TOTAL	66,432	4.475	2,973,141	5.115	3,397,834	424,693

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Residential Bill Comparison

	Current Sep-Dec - 2021 (\$/1000 kWh)	Requested Average -2022 ¹ (\$/1000 kWh)	Difference from Current	
			\$	%
Base Rate ^{2 3}	\$74.89	\$80.91	\$6.02	8.04%
Fuel Cost Recovery	32.28	36.81	4.53	14.03%
Capacity Cost Recovery (CCR)	14.05	11.55	(2.50)	-17.79%
Energy Conservation Cost Recovery (ECCR)	3.38	2.83	(0.55)	-16.27%
Environmental Cost Recovery (ECRC)	0.99	0.28	(0.71)	-71.72%
Storm Protection Plan Cost Recovery Charge (SPPCRC)	0.31	3.00	2.69	866.25%
Interim Storm Charge	0.55	0.00	(0.55)	-100.00%
Asset Securitization Charge (ASC)	2.48	2.48	0.00	0.00%
Subtotal	128.93	137.85	8.92	6.92%
Gross Receipts Tax and Regulatory Assessment Fee ⁴	3.31	3.63	0.32	9.67%
Total	\$132.24	\$141.48	\$9.24	6.99%

¹ Based on DEF Rate Mitigation Plan pending Commission approval in the instant docket.

² For 2022, reflects the average bill impact for a Residential customer using 1,000 kWh.

³ Base Rate is in accordance with the 2021 Settlement Agreement approved in Order No. PSC-2021-0202-AS-EI.

⁴ Per the 2021 Settlement Agreement, the Regulatory Assessment Fee (RAF) has been removed from base rates and recovery clauses and included on customer bills on the same line as Gross Receipts Tax beginning with January 2022 billing.

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Calculation of Inverted Residential Fuel Factors

	Annual Units mWh	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues	Inverted Fuel Rates Cents/kWh	Annual Fuel Revenues
Residential Excluding TOU:					
0 - 1,000 kWh	13,066,657	3.992	\$ 521,620,934	3.681	\$ 480,976,406
Over 1,000 kWh	5,355,406	3.992	213,787,810	4.751	254,432,380
Total	<u>18,422,062</u>		<u>\$ 735,408,744</u>		<u>\$ 735,408,786</u>
Rate Differential by Tier - Cents per kWh				1.070	
Residential Sales:					
Total	21,211,129				
Time of Use	<u>2,789,068</u>				
Levelized	<u>18,422,062</u>				

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Generating System Comparative Data by Fuel Type

	2019 Actual	2020 Actual	2021 Actual/Estimated	2022 Projection	2020 vs. 2019	2021 vs. 2020	2022 vs. 2021
FUEL COST OF SYSTEM NET GENERATION (\$)							
LIGHT OIL	14,226,223	14,118,488	29,480,919	25,097,854	-0.8%	108.8%	-14.9%
COAL	161,620,864	128,688,321	223,609,330	225,160,632	-20.4%	73.8%	0.7%
GAS	1,055,035,576	931,534,138	1,066,095,782	1,091,864,480	-11.7%	14.4%	2.4%
OTHER	0	0	0	0	0.0%	0.0%	0.0%
TOTAL \$	1,230,882,664	1,074,340,946	1,319,186,031	1,342,122,966	-12.7%	22.8%	1.7%
SYSTEM NET GENERATION (mWh)							
LIGHT OIL	52,512	33,060	102,419	154,432	-37.0%	209.8%	50.8%
COAL	4,300,231	3,287,271	7,479,494	7,962,261	-23.6%	127.5%	6.5%
GAS	35,165,359	36,327,454	31,767,946	30,336,977	3.3%	-12.6%	-4.5%
SOLAR	214,679	706,116	1,061,091	2,101,192	228.9%	50.3%	98.0%
OTHER	0	0	0	0	0.0%	0.0%	0.0%
TOTAL mWh	39,732,780	40,353,901	40,410,950	40,554,861	1.6%	0.1%	0.4%
UNITS OF FUEL BURNED							
LIGHT OIL BBL	121,326	117,843	273,508	232,174	-2.9%	132.1%	-15.1%
COAL TON	1,976,271	1,562,463	3,349,822	3,543,136	-20.9%	114.4%	5.8%
GAS MCF	262,546,275	269,892,525	234,032,447	218,011,155	2.8%	-13.3%	-6.8%
OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
LIGHT OIL	698,679	633,568	1,582,166	1,352,467	-9.3%	149.7%	-14.5%
COAL	44,098,849	35,171,675	76,302,631	81,126,471	-20.2%	116.9%	6.3%
GAS	268,325,594	276,672,797	236,851,712	218,011,155	3.1%	-14.4%	-8.0%
OTHER	0	0	0	0	0.0%	0.0%	0.0%
TOTAL MMBTU	313,123,122	312,478,040	314,736,509	300,490,093	-0.2%	0.7%	-4.5%
GENERATION MIX (% mWh)							
LIGHT OIL	0.13%	0.08%	0.25%	0.38%	-75.8%	243.9%	39.5%
COAL	10.82%	8.15%	18.51%	19.63%	-24.9%	127.7%	5.9%
GAS	88.51%	90.02%	78.61%	74.81%	1.7%	-12.7%	-4.8%
SOLAR	0.54%	1.75%	2.63%	5.18%	222.2%	51.4%	99.0%
OTHER	0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
TOTAL %	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
FUEL COST PER UNIT							
LIGHT OIL \$/BBL	117.26	119.81	107.79	108.10	2.2%	-10.0%	0.3%
COAL \$/TON	81.78	82.36	66.75	63.55	0.7%	-19.0%	-4.8%
GAS \$/MCF	4.02	3.45	4.56	5.01	-14.1%	32.0%	9.9%
OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU (\$/MMBTU)							
LIGHT OIL	20.36	22.28	18.63	18.56	9.4%	-16.4%	-0.4%
COAL	3.67	3.66	2.93	2.78	-0.2%	-19.9%	-5.3%
GAS	3.93	3.37	4.50	5.01	-14.4%	33.7%	11.3%
OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL \$/MMBTU	3.93	3.44	4.19	4.47	-12.5%	21.9%	6.6%
BTU BURNED PER kWh (BTU/kWh)							
LIGHT OIL	13,305	19,164	15,448	8,758	44.0%	-19.4%	-43.3%
COAL	10,255	10,699	10,202	10,189	4.3%	-4.7%	-0.1%
GAS	7,630	7,616	7,456	7,186	-0.2%	-2.1%	-3.6%
OTHER	0	0	0	0	0.0%	0.0%	0.0%
TOTAL BTU/kWh	7,881	7,743	7,788	7,409	-1.7%	0.6%	-4.9%
GENERATED FUEL COST PER kWh (C/kWh)							
LIGHT OIL	27.09	42.71	28.78	16.25	57.6%	-32.6%	-43.5%
COAL	3.76	3.91	2.99	2.83	4.2%	-23.6%	-5.4%
GAS	3.00	2.56	3.36	3.60	-14.5%	30.9%	7.2%
OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL C/kWh	3.10	2.66	3.26	3.31	-14.1%	22.6%	1.4%

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 2022 through December 2022

	(1)	(2)	(3)	(4)
	Jurisdictional Rate Base			
	Adjusted Retail (\$000s)	Cap Ratio	Cost Rate	Weighted Cost
1 Common Equity	\$ 7,302,840	43.96%	9.85%	4.330%
2 Long Term Debt	6,603,424	39.75%	4.11%	1.635%
3 Short Term Debt	74,501	0.45%	1.66%	0.007%
4 Cust Dep Active	182,161	1.10%	2.36%	0.026%
5 Cust Dep Inactive	1,888	0.01%		
6 Invest Tax Cr	215,728	1.30%	7.13%	0.093%
7 Deferred Inc Tax	2,230,499	13.43%		
8 Total	\$ 16,611,041	100.00%		6.09%
	<u>ITC split between Debt and Equity**:</u>		<u>Ratio</u>	<u>Cost Rate</u>
9	Common Equity	7,302,840	53%	9.9%
10	Preferred Equity	-	0%	
11	Long Term Debt	6,603,424	47%	4.11%
12		13,906,264	100%	
13	<u>Breakdown of Revenue Requirement Rate of Return between Debt and Equity:</u>			
14	Total Equity Component (Lines 1 and 9)			
	Total Debt Component (Lines 2, 3 , 4 , and 11)			

DUKE ENERGY FLORIDA, LLC
Fuel and Capacity Cost Recovery Factor
January through December 2022

PART 3 – 2022 CAPACITY COST RECOVERY SCHEDULES

Schedule E12-A – Calculation of Projected Capacity Costs

Schedule E12-B – Calculation of Actual/Estimated True-up

Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

	EST Jan-22	EST Feb-22	EST Mar-22	EST Apr-22	EST May-22	EST Jun-22	EST Jul-22	EST Aug-22	EST Sep-22	EST Oct-22	EST Nov-22	EST Dec-22	TOTAL
1 <u>Base Production Level Capacity Costs</u>													
2 Orange Cogen (ORANGE CO)	6,502,741	6,502,741	6,502,741	6,502,741	6,502,741	6,502,741	6,502,741	6,502,741	6,502,741	6,502,741	6,502,741	6,502,741	78,032,895
3 Orlando Cogen Limited (ORLACOGL)	6,542,615	6,542,615	6,542,615	6,542,615	6,542,615	6,542,615	6,542,615	6,542,615	6,542,615	6,542,615	6,542,615	6,542,615	78,511,375
4 Pasco County Resource Recovery (PASCOUNT)	2,429,950	2,429,950	2,429,950	2,429,950	2,429,950	2,429,950	2,429,950	2,429,950	2,429,950	2,429,950	2,429,950	2,429,950	29,159,400
5 Pinellas County Resource Recovery (PINCOUNT)	5,784,338	5,784,338	5,784,338	5,784,338	5,784,338	5,784,338	5,784,338	5,784,338	5,784,338	5,784,338	5,784,338	5,784,338	69,412,050
6 Polk Power Partners, L.P. (MULBERRY/ROYSTER)	8,932,174	8,932,174	8,932,174	8,932,174	8,932,174	8,932,174	8,932,174	8,932,174	8,932,174	8,932,174	8,932,174	8,932,174	107,186,091
7 Subtotal - Base Level Capacity Costs	30,191,818	30,191,818	30,191,818	30,191,818	30,191,818	30,191,818	30,191,818	30,191,818	30,191,818	30,191,818	30,191,818	30,191,818	362,301,812
8 Base Production Jurisdictional Responsibility	92.865%	92.865%	92.865%	92.865%	92.865%	92.865%	92.865%	92.865%	92.865%	92.865%	92.865%	92.865%	
9 Base Level Jurisdictional Capacity Costs	28,037,631	28,037,631	28,037,631	28,037,631	28,037,631	28,037,631	28,037,631	28,037,631	28,037,631	28,037,631	28,037,631	28,037,631	336,451,572
10 <u>Intermediate Production Level Capacity Costs</u>													
11 Southern Franklin	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Schedule H Capacity Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
13 Subtotal - Intermediate Level Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
14 Intermediate Production Jurisdictional Responsibility	88.321%	88.321%	88.321%	88.321%	88.321%	88.321%	88.321%	88.321%	88.321%	88.321%	88.321%	88.321%	
15 Intermediate Level Jurisdictional Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
16 <u>Peaking Production Level Capacity Costs</u>													
17 Shady Hills	1,978,186	1,978,186	1,412,990	1,370,811	1,919,136	3,901,540	3,901,540	3,901,540	1,820,718	1,370,811	1,370,811	1,978,186	26,904,454
18 Vandolah (NSG)	2,849,660	2,865,669	2,053,407	2,030,537	2,769,615	5,712,588	5,695,435	5,649,696	2,702,911	1,990,514	2,036,254	2,865,669	39,221,954
19 Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20 Subtotal - Peaking Level Capacity Costs	4,827,846	4,843,855	3,466,397	3,401,348	4,688,751	9,614,127	9,596,975	9,551,235	4,523,630	3,361,326	3,407,065	4,843,855	66,126,409
21 Peaking Production Jurisdictional Responsibility	90.678%	90.678%	90.678%	90.678%	90.678%	90.678%	90.678%	90.678%	90.678%	90.678%	90.678%	90.678%	
22 Peaking Level Jurisdictional Capacity Costs	4,377,810	4,392,326	3,143,270	3,084,285	4,251,681	8,717,930	8,702,376	8,660,900	4,101,952	3,047,994	3,089,470	4,392,326	59,962,320
23 <u>Other Capacity Costs</u>													
24 Retail Wheeling	(97,224)	(67,173)	(68,704)	(32,696)	(33,949)	(32,834)	(28,573)	(43,973)	(42,525)	(39,470)	(30,963)	(40,149)	(558,233)
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 CR1&2 NBV ²	45,460	45,460	45,460	45,460	45,460	45,460	45,460	45,460	45,460	45,460	45,460	45,460	545,523
27 SoBRA True-Up - Santa Fe ⁴	(257,563)												(257,563)
28 SoBRA True-Up - Twin Rivers ⁴	(355,679)												(355,679)
29 SoBRA True-Up - Santa Fe (Base Rate Adjmt) ⁴	(32,191)	(32,191)	(32,191)	(32,191)	(32,191)	(32,191)	(32,191)	(32,191)	(32,191)	(32,191)	(32,191)	(32,191)	(386,291)
30 SoBRA True-Up - Twin Rivers (Base Rate Adjmt) ⁴	(44,454)	(44,454)	(44,454)	(44,454)	(44,454)	(44,454)	(44,454)	(44,454)	(44,454)	(44,454)	(44,454)	(44,454)	(533,447)
31 Total Other Capacity Costs	(75,407)	564,420	559,420	591,961	587,241	584,888	585,681	566,814	564,793	564,380	569,420	556,767	6,220,377
32 Total Capacity Costs (line 9+15+22+31)	32,340,034	32,994,377	31,740,321	31,713,877	32,876,553	37,340,449	37,325,688	37,265,345	32,704,376	31,650,005	31,696,521	32,986,724	402,634,269
33 Actual/Estimated True-Up Provision - Jan - Dec 2020													(2,718,273)
34 Total Recoverable Capacity Costs													399,915,997
35 Total Recoverable ISFSI Costs ³													6,885,232
36 Total Recoverable Capacity & ISFSI Costs (line 34+35)													406,801,229

¹ Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
² As approved in Order No. PSC-2021-0024-FOF-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. (MULBERRY/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

	ACT Jan-21	ACT Feb-21	ACT Mar-21	ACT Apr-21	ACT May-21	ACT Jun-21	ACT Jul-21	EST Aug-21	EST Sep-21	EST Oct-21	EST Nov-21	EST Dec-21	TOTAL
1 <u>Base Production Level Capacity Costs</u>													
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	101,978,673
7 Subtotal - Base Level Capacity Costs	28,627,814	28,642,512	28,635,163	28,635,163	28,635,163	28,635,163	28,635,163	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	343,621,954
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 <u>Intermediate Production Level Capacity Costs</u>													
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	244,901	-	-	-	-	-	465,050
13 Subtotal - Intermediate Level Capacity Costs	4,826,760	4,988,816	2,913,671	2,914,969	3,198,304	(529,369)	244,901	-	-	-	-	-	18,558,052
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)	178,050	-	-	-	-	-	13,492,261
16 <u>Peaking Production Level Capacity Costs</u>													
17 Shady Hills	1,976,940	1,976,940	1,976,940	804,060	1,916,460	3,896,100	4,825,132	3,901,540	1,820,718	1,370,811	1,370,811	1,978,186	27,814,638
18 Vandolah (NSG)	3,033,279	2,968,686	2,017,074	1,998,157	2,873,617	5,948,748	3,950,401	5,649,696	2,702,911	1,990,514	2,036,254	2,865,669	38,035,006
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	8,775,533	9,551,235	4,523,630	3,361,326	3,407,065	4,843,855	65,849,644
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	8,417,842	9,161,927	4,339,247	3,224,318	3,268,193	4,646,419	63,165,613
23 <u>Other Capacity Costs</u>													
24 Retail Wheeling	-	(19,418)	(4,147)	(1,634)	-	-	-	5,793	8,981	24,821	39,349	36,727	90,471
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)	(2,793,310)
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	7,130,548	7,132,811	7,132,469	7,144,779	7,155,776	7,149,624	85,678,237
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	42,324,211	42,892,509	38,069,487	36,966,868	37,021,740	38,393,814	481,509,364
30 ISFSI Revenue Requirement³	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	42,897,531	43,465,829	38,642,807	37,540,187	37,595,060	38,967,133	488,389,201
32 <u>Capacity Revenues</u>													
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	46,088,175	48,407,053	47,602,322	44,377,097	36,846,812	34,874,816	485,041,956
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	46,049,585	48,368,462	47,563,732	44,338,507	36,808,222	34,836,226	484,578,871
36 <u>True-Up Provision</u>													
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	3,152,054	4,902,633	8,920,925	6,798,319	(786,838)	(4,130,908)	(3,810,329)
38 Interest Provision for the Month	249	(425)	(883)	(1,181)	(862)	(865)	(886)	(247)	22	227	204	82	(4,567)
39 Current Cycle Balance - Over/(Under)	(6,768,012)	(14,943,722)	(19,462,182)	(22,484,117)	(24,482,401)	(22,670,481)	(19,519,313)	(14,616,927)	(5,695,980)	1,102,565	315,932	(3,814,895)	(3,814,896)
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)	(\$16,368,857)	(\$13,179,100)	(\$8,238,121)	\$721,416	\$7,558,552	\$6,810,509	\$2,718,273	\$2,718,273

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 Order No. PSC-2016-0425-PAA-EI.

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (MWh)	(3) Avg 12 CP at Meter (MW)	(4) Delivery Efficiency Factor	(5) Sales at Source (Generation) (MWh)	(6) Avg 12 CP at Source (MW)	(7) Annual Average Demand (MWh)	(8) Annual Average Demand Allocator (%)	(9) 12CP Allocator (%)	(10) 12 CP & 25% AD Demand Allocator (%)	(11) Base Energy & Demand Revenues (\$000s)	(12) ISFSI Uniform Percent Allocation (\$000s)
Residential												0.30%
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	0.516	21,211,130	4,691.5	0.9361197	22,658,567	5,011.7	2,586.6	54.164%	64.006%	61.546%	1,503,887	4,520
General Service Non-Demand												
GS-1, GST-1												
Secondary	0.608	1,018,417	191.2	0.9361197	1,087,914	204.3	124.2	2.601%	2.609%	2.607%		
Primary	0.608	18,782	3.5	0.9759311	19,246	3.6	2.2	0.046%	0.046%	0.046%		
Sec Del/Primary Mtr	0.608	42	0.0	0.9759311	43	0.0	0.0	0.000%	0.000%	0.000%		
Transmission	0.608	2,666	0.5	0.9859311	2,704	0.5	0.3	0.006%	0.006%	0.006%		
		1,039,908	195.3		1,109,907	208.4	126.7	2.653%	2.662%	2.660%	73,799	222
General Service												
GS-2 Secondary	1.000	204,533	23.3	0.9361197	218,490	24.9	24.9	0.522%	0.319%	0.369%	5,589	17
General Service Demand												
GSD-1, GSDT-1												
Secondary	0.742	11,642,447	1,791.3	0.9361197	12,436,921	1,913.6	1,419.7	29.730%	24.439%	25.762%		
Primary	0.742	1,638,508	252.1	0.9759311	1,678,917	258.3	191.7	4.013%	3.299%	3.478%		
Sec Del/Primary Mtr	0.742	24,351	3.7	0.9759311	24,952	3.8	2.8	0.060%	0.049%	0.052%		
Transm Del/ Primary Mtr	0.742	0	0.0	0.9759311	0	0.0	0.0	0.000%	0.000%	0.000%		
Transmission	0.742	401,077	61.7	0.9859311	406,800	62.6	46.4	0.972%	0.799%	0.843%		
SS-1 Primary	0.958	48,108	5.7	0.9759311	49,294	5.9	5.6	0.118%	0.075%	0.086%		
Transm Del/ Transm Mtr	0.958	3,723	0.4	0.9859311	3,776	0.4	0.4	0.009%	0.006%	0.007%		
Transm Del/ Primary Mtr	0.958	1,546	0.2	0.9759311	1,585	0.2	0.2	0.004%	0.002%	0.003%		
		13,759,760	2,115.2		14,602,246	2,244.8	1,666.9	34.906%	28.670%	30.229%	623,294	1,874
Curtailable												
CS-2, CST-2, CS-3, CST-3												
Secondary	1.028	0	0.0	0.9361197	0	0.0	0.0	0.000%	0.000%	0.000%		
Primary	1.028	62,060	6.9	0.9759311	63,590	7.1	7.3	0.152%	0.090%	0.106%		
SS-3 Primary	2.390	58,185	2.8	0.9759311	59,620	2.8	6.8	0.143%	0.036%	0.063%		
		120,244	9.7		123,210	9.9	14.1	0.295%	0.127%	0.169%	5,466	16
Interruptible												
IS-2, IST-2												
Secondary	0.957	406,762	48.5	0.9361197	434,520	51.8	49.6	1.039%	0.662%	0.756%		
Sec Del/Primary Mtr	0.957	5,152	0.6	0.9759311	5,279	0.6	0.6	0.013%	0.008%	0.009%		
Primary Del / Primary Mtr	0.957	1,171,449	139.7	0.9759311	1,200,340	143.2	137.0	2.869%	1.828%	2.089%		
Primary Del / Transm Mtr	0.957	226	0.0	0.9859311	229	0.0	0.0	0.001%	0.000%	0.000%		
Transm Del/ Transm Mtr	0.957	599,084	71.5	0.9859311	607,632	72.5	69.4	1.453%	0.926%	1.057%		
Transm Del/ Primary Mtr	0.957	429,008	51.2	0.9759311	439,588	52.4	50.2	1.051%	0.670%	0.765%		
SS-2 Primary	1.147	13,316	1.3	0.9759311	13,644	1.4	1.6	0.033%	0.017%	0.021%		
Transm Del/ Transm Mtr	1.147	1,250	0.1	0.9859311	1,268	0.1	0.1	0.003%	0.002%	0.002%		
Transm Del/ Primary Mtr	1.147	44,422	4.4	0.9759311	45,518	4.5	5.2	0.109%	0.058%	0.071%		
		2,670,669	317.4		2,748,019	326.6	313.7	6.569%	4.171%	4.770%	68,700	207
Lighting												
LS-1 (Secondary)	11.683	348,815	3.4	0.9361197	372,618	3.6	42.5	0.891%	0.046%	0.258%	9,900	30
		39,355,060	7,356		41,833,056	7,830	4,775	100.000%	100.000%	100.000%	2,290,635	6,885

Notes:

- (1) Average 12CP load factor based on load research study filed July 30, 2021 (FPSC rule 25-6.0437 (7))
(2) Projected mWh sales for the period Jan-Dec 2022
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) Based on system average line loss analysis for 2020
(5) Calculated: Column 2 / Column 4
(6) Calculated: Column 3 / Column 4

- (7) Calculated: Column 5 / 8,760 hours
(8) Calculated: Column 7 / Total Column 7
(9) Calculated: Column 6 / Total Column 6
(10) Calculated: Column 8 x 1/4 + Column 9 x 3/4
(11) Projected Base Energy & Demand Revenues for Jan-Dec 2022
(12) Uniform Percent Calculated: Column 12 Total / Column 11 Total
Calculated: Column 11 x Uniform Percent

Rate Class	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	12 CP & 25% AD Demand Allocator (%)	Effective mWh at Secondary Level (MWh)	Capacity Production Demand Costs (\$)	ISFSI Dry Cask Storage Costs (\$)	Capacity + ISFSI Production Demand Costs (\$)	Capacity CCR Factor (c/kWh)	ISFSI CCR Factor (c/kWh)	Capacity + ISFSI CCR Factor (c/kWh)	Billing KW Load Factor (%)	Projected Effective KW at Meter Level (kW)	Capacity CCR Factor (\$/kW-mo)	ISFSI CCR Factor (\$/kW-mo)	Capacity + ISFSI CCR Factor (\$/kW-mo)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	61.546%	21,211,130	\$246,131,188	\$4,520,411	\$250,651,599	1.160	0.021	1.181					
General Service Non-Demand													
GS-1, GST-1													
Secondary		1,018,417				1.023	0.021	1.044					
Primary		18,636				1.013	0.021	1.034					
Transmission		2,613				1.003	0.021	1.023					
TOTAL GS	2.660%	1,039,667	10,635,922	221,828	10,857,749								
General Service													
GS-2 Secondary	0.369%	204,533	1,477,610	16,799	1,494,409	0.722	0.008	0.730					
General Service Demand													
GSD-1, GSDT-1, SS-1													
Secondary		11,642,447									2.99	0.05	3.04
Primary		1,695,388									2.96	0.05	3.01
Transmission		396,704									2.93	0.05	2.98
TOTAL GSD	30.229%	13,734,539	120,889,717	1,873,507	122,763,224				46.61%	40,367,597			
Curtaillable													
CS-2, CST-2, CS-3, CST-3, SS-3													
Secondary		-									1.23	0.03	1.26
Primary		119,042									1.22	0.03	1.25
Transmission		-									1.21	0.03	1.23
TOTAL CS	0.169%	119,042	674,143	16,429	690,572				29.79%	547,429			
Interruptible													
IS-2, IST-2, SS-2													
Secondary		406,762									2.38	0.03	2.40
Primary		1,646,714									2.36	0.03	2.38
Transmission		588,548									2.33	0.03	2.35
TOTAL IS	4.770%	2,642,025	19,077,408	206,501	19,283,909				45.10%	8,024,557			
Lighting													
LS-1 Secondary	0.258%	348,815	1,030,009	29,758	1,059,767	0.295	0.009	0.304					
	100.000%	39,299,750	\$399,915,997	\$6,885,232	\$406,801,229	1.018	0.018	1.036					

Notes:

- (1) From Schedule E12-D, Column 10

(2) Projected mWh sales at effective voltage level for Jan-Dec 2022

(3) Column 1 x Total Recoverable Capacity Costs (Schedule E12-A)

(4) From Schedule E12-D, Column 12

(5) Column 3 + Column 4

(6) (Column 3 / Column 2) / 10

(7) (Column 4 / Column 2) / 10
- (8) Column 6 + Column 7

(9) Class Billing kW Load Factor

(10) Column 2 x 1000 / 8,760 / Column 9 x 12

(11) Column 3 / Column 10

(12) Column 4 / Column 10

(13) Column 5 / Column 10

*Calculation of Standby Service kW Charges:			
	Capacity + Ridge + ISFSI Cost	Effective kW	\$/kW
Total GSD, CS, IS	\$142,737,705	48,939,583	2.92
SS-1, 2, 3 - \$/kW-mo	Secondary	Primary	Trans
Monthly - \$2.92/kW * 10%	0.292	0.289	0.286
Daily - \$2.92/kW / 21	0.139	0.138	0.136

Rate Class	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	12 CP & 25% AD Demand Allocator (%)	Effective mWh at Secondary Level (MWh)	SoBRA Production Demand Costs (\$)	SoBRA CCR Factor (c/kWh)	Billing KW Load Factor (%)	Projected Effective KW at Meter Level (kW)	SoBRA CCR Factor (\$/kW-mo)
Residential							
RS-1, RST-1, RSL-1, RSL-2, RSS-1							
Secondary	61.546%	5,831,523	-\$4,545,828	-0.078			
General Service Non-Demand							
GS-1, GST-1							
Secondary		240,880		-0.078			
Primary		8,670		-0.077			
Transmission		862		-0.076			
TOTAL GS	2.660%	250,411	-196,436				
General Service							
GS-2							
Secondary	0.369%	58,196	-27,290	-0.047			
General Service Demand							
GSD-1, GSDT-1, SS-1							
Secondary		3,412,506					-0.19
Primary		498,833					-0.19
Transmission		110,704					-0.19
TOTAL GSD	30.229%	4,022,043	-2,232,727		46.61%	11,821,306	
Curtable							
CS-2, CST-2, CS-3, CST-3, SS-3							
Secondary		-					-0.07
Primary		37,572					-0.07
Transmission		-					-0.07
TOTAL CS	0.169%	37,572	-12,451		29.79%	172,781	
Interruptible							
IS-2, IST-2, SS-2							
Secondary		123,918					-0.14
Primary		532,433					-0.14
Transmission		174,407					-0.14
TOTAL IS	4.770%	830,758	-352,343		45.10%	2,523,242	
Lighting							
LS-1							
Secondary	0.258%	102,186	-19,023	-0.019			
	100.000%	11,132,689	-\$7,386,099	-0.066			

Notes:

(1) From Schedule E12-D, Column 10

(2) Projected mWh sales at effective voltage level for Jan-Dec 2022

(3) Column 1 x Total Recoverable SoBRA Costs (Schedule E12-A)

(4) (Column 3 / Column 2) / 10

(5) Class Billing kW Load Factor

(6) Column 2 x 1000 / 8,760 / Column 5 x 12

(7) Column 3 / Column 6

*Calculation of Standby Service kW Charges:			
	SoBRA Cost	Effective kW	\$/kW
Total GSD, CS, IS	(\$2,597,521)	14,517,329	(0.18)
SS-1, 2, 3 - \$/kW-mo	Secondary	Primary	Trans
Monthly - \$-0.18/kW * 10%	(0.018)	(0.018)	(0.018)
Daily - \$-0.18/kW / 21	(0.009)	(0.009)	(0.009)

Rate Class	(1)	(2)	(3)	(4)	(5)	(6)
	Jan - Apr 2022			Jan - Apr 2022		
	Capacity + ISFSI CCR Factor (c/kWh)	SoBRA CCR Factor (c/kWh)	CCR Factor (c/kWh)	Capacity + ISFSI CCR Factor (\$/kW-mo)	SoBRA CCR Factor (c/kWh)	Capacity + ISFSI CCR Factor (\$/kW-mo)
Residential						
RS-1, RST-1, RSL-1, RSL-2, RSS-1						
Secondary	1.181	-0.078	1.103			
General Service Non-Demand						
GS-1, GST-1						
Secondary	1.044	-0.078	0.966			
Primary	1.034	-0.077	0.956			
Transmission	1.023	-0.076	0.947			
TOTAL GS						
General Service						
GS-2						
Secondary	0.730	-0.047	0.683			
General Service Demand						
GSD-1, GSDT-1, SS-1						
Secondary				3.04	-0.19	2.85
Primary				3.01	-0.19	2.82
Transmission				2.98	-0.19	2.79
TOTAL GSD						
Curtable						
CS-2, CST-2, CS-3, CST-3, SS-3						
Secondary				1.26	-0.07	1.19
Primary				1.25	-0.07	1.18
Transmission				1.23	-0.07	1.16
TOTAL CS						
Interruptible						
IS-2, IST-2, SS-2						
Secondary				2.40	-0.14	2.26
Primary				2.38	-0.14	2.24
Transmission				2.35	-0.14	2.21
TOTAL IS						
Lighting						
LS-1						
Secondary	0.304	-0.019	0.285			
	1.036	-0.066	0.970			

Notes:

(1) From Schedule E12-E Page 1, Column 8

(2) From Schedule E12-E Page 2, Column 4

(3) Column 1 + Column 2

(4) From Schedule E12-E Page 1, Column 13

(5) From Schedule E12-E Page 2, Column 7

(6) Column 4 + Column 5

*Calculation of Standby Service kW Charges:			
			\$/kW
Total GSD, CS, IS			2.74
SS-1, 2, 3 - \$/kW-mo	Secondary	Primary	Trans
Monthly - \$2.74/kW * 10%	0.274	0.271	0.268
Daily - \$2.74/kW / 21	0.130	0.129	0.127



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

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 Page 3 of 9 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 treated.)

Laminated generator synchronizing guidance (operator aid) did not exist for unit 4. Exhibit No. (JS-1)

Witness: Simpson

Page 5 of 9

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		
<i>A4B5C09 – Change-related documents not developed or revised</i>		
Corrective Action Describe specific actions taken or required.	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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 <u>SHALL</u> 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)			Witness: Simpson
Contributing Cause(s):	A3B3C04 – LTA review based on assumption that process will not change		Exhibit No. (JS-1)
	A4B2C04 – Resources not provided to assure adequate training was provided/ maintained		Page 6 of 9
	A3B3C06 – Individual underestimated the problem by using past events as basis		
	A6B2C01 – Practice or “hands-on” experience LTA		
Corrective Action	Assignee	Due/Completion Date	
Describe specific actions taken or required	Evaluator SHALL obtain concurrence from assignee or supervisor		
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	Assignee	Due/Completion Date
Describe specific actions taken or required	Evaluator SHALL obtain concurrence from assignee or supervisor	
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	Assignee	Due/Completion Date
Describe specific actions taken or required	Evaluator SHALL obtain concurrence from assignee or supervisor	
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 <u>SHALL</u> 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

Witness: Simpson
Exhibit No. ____ (JS-1)
Page 7 of 9

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



RMA 21184 DUKE
ENERGY EVALUATION

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



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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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

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:	<i>Roger Magler</i>	Date:	<i>2/8/2021</i>

CONFIDENTIAL

GPIF REWARD/PENALTY SCHEDULES

<u>Description</u>	<u>Sheet</u>
Index	1
Reward/Penalty Table (Actual)	2
Calculation of Maximum Incentive Dollars (Actual)	3
Calculation of System Actual GPIF Points	4
GPIF Unit Performance Summary	5
Actual Unit Performance Data	6
Adjustments to EAF Actual	7
Adjustments to ANOHR Actual	8
Generating Performance Incentive Points Table	9-14
Actual Unit Performance Data	15-20
Planned Outage Schedules (Actual)	21-22

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Duke Energy Florida
January 2020 - December 2020

Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss (\$)	Generating Performance Incentive Factor (\$)
10	\$ 21,933,791	\$ 10,966,895
9	\$ 19,740,412	\$ 9,870,206
8	\$ 17,547,033	\$ 8,773,516
7	\$ 15,353,653	\$ 7,676,827
6	\$ 13,160,274	\$ 6,580,137
5	\$ 10,966,895	\$ 5,483,448
4	\$ 8,773,516	\$ 4,386,758
3	\$ 6,580,137	\$ 3,290,069
**** 2.423	\$ 5,314,557	\$ 2,657,279
2	\$ 4,386,758	\$ 2,193,379
1	\$ 2,193,379	\$ 1,096,690
0	\$ -	\$ -
-1	\$ (2,654,018)	\$ (1,096,690)
-2	\$ (5,308,036)	\$ (2,193,379)
-3	\$ (7,962,054)	\$ (3,290,069)
-4	\$ (10,616,072)	\$ (4,386,758)
-5	\$ (13,270,090)	\$ (5,483,448)
-6	\$ (15,924,108)	\$ (6,580,137)
-7	\$ (18,578,126)	\$ (7,676,827)
-8	\$ (21,232,144)	\$ (8,773,516)
-9	\$ (23,886,162)	\$ (9,870,206)
-10	\$ (26,540,180)	\$ (10,966,895)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Duke Energy Florida
January 2020 - December 2020

1	Beginning of period balance of common equity	\$ 6,789,687,410	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2020	\$ 6,836,681,418	
3	Month of FEBRUARY 2020	\$ 6,860,099,665	
4	Month of MARCH 2020	\$ 6,914,768,481	
5	Month of APRIL 2020	\$ 6,966,118,515	
6	Month of MAY 2020	\$ 7,055,715,006	
7	Month of JUNE 2020	\$ 7,126,999,823	
8	Month of JULY 2020	\$ 7,230,062,584	
9	Month of AUGUST 2020	\$ 7,333,848,937	
10	Month of SEPTEMBER 2020	\$ 7,411,196,758	
11	Month of OCTOBER 2020	\$ 7,487,364,734	
12	Month of NOVEMBER 2020	\$ 7,523,963,803	
13	Month of DECEMBER 2020	\$ 7,558,921,452	
14	Average common equity for the period	\$ 7,161,186,814	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	75.2739%	
17	Maximum allowed incentive dollars	\$ 23,783,771	
18	Jurisdictional Sales *	39,240,079	MWH
19	Total Sales *	39,484,848	MWH
20	Jurisdictional Separation Factor	99.3800%	
21	Maximum allowed jurisdictional incentive dollars	\$ 23,636,312	
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 6.101.1	\$ 10,966,895	
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	\$ 10,966,895	
*	Net sales (Sales - Interruptible)		

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Duke Energy Florida
January 2020 - December 2020

<u>Plant/Unit</u>	<u>Performance Indicator EAF or ANOHR</u>	<u>Weighting Factor %</u>	<u>Unit Points</u>	<u>Weighted Unit Points</u>
Bartow CC	EAF	7.37	10.000	0.737
	ANOHR	30.88	4.736	1.463
Hines 1	EAF	0.73	-3.647	-0.027
	ANOHR	12.12	-0.474	-0.057
Hines 2	EAF	0.11	-10.000	-0.011
	ANOHR	8.83	0.000	0.000
Hines 3	EAF	0.72	-3.468	-0.025
	ANOHR	9.52	0.000	0.000
Hines 4	EAF	3.95	9.065	0.358
	ANOHR	7.34	0.000	0.000
Osprey CC	EAF	2.38	-0.621	-0.015
	ANOHR	16.03	0.000	0.000

GPIF System	100.00	2.423
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GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Duke Energy Florida
January 2020 - December 2020

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE		Max. Fuel Savings (\$000)	Max. Fuel Loss (\$000)	EAF Adjusted Actual (%)	Estimated
			Max. (%)	Min. (%)				Fuel Savings/ Loss (\$000)
Bartow CC	7.37	88.20	92.74	79.17	\$1,617	(\$2,661)	95.52	\$1,617
Hines 1	0.73	87.02	89.01	82.98	\$160	(\$785)	85.55	(\$286)
Hines 2	0.11	90.32	91.15	88.60	\$25	(\$447)	88.19	(\$447)
Hines 3	0.72	93.73	94.89	91.35	\$159	(\$726)	92.91	(\$252)
Hines 4	3.95	83.95	87.02	77.60	\$866	(\$2,199)	86.73	\$785
Osprey CC	2.38	88.14	91.02	82.23	\$521	(\$1,136)	87.78	(\$71)

GPIF System	15.26				\$3,347.9	(\$7,954.3)		\$1,346.6
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Plant/Unit	Weighting Factor (%)	ANOHR		ANOHR RANGE		Max. Fuel Savings (\$000)	Max. Fuel Loss (\$000)	ANOHR Adjusted Actual (Btu/kwh)	Estimated
		Target (BTU/KWH)	NOF	Min. (Btu/kwh)	Max. (Btu/kwh)				Fuel Savings/ Loss (\$000)
Bartow CC	30.88	7,892	72.9	7,496	8,289	\$6,774	(\$6,774)	7,665	\$3,208
Hines 1	12.12	7,261	88.0	6,922	7,600	\$2,659	(\$2,659)	7,348	(\$126)
Hines 2	8.83	7,410	83.9	7,159	7,660	\$1,937	(\$1,937)	7,441	\$0
Hines 3	9.52	7,266	80.5	7,019	7,514	\$2,089	(\$2,089)	7,250	\$0
Hines 4	7.34	6,982	91.7	6,801	7,162	\$1,611	(\$1,611)	7,025	\$0
Osprey CC	16.03	7,291	58.6	6,717	7,866	\$3,517	(\$3,517)	7,336	\$0

GPIF System	84.74					\$18,585.9	(\$18,585.9)		\$3,082.0
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GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida
January 2020 - December 2020

Plant/Unit	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	ADJUSTED ACTUAL EAF %
Bartow CC	92.94	2.58	95.52
Hines 1	85.55	0.00	85.55
Hines 2	82.59	5.61	88.19
Hines 3	96.60	-3.69	92.91
Hines 4	84.36	2.37	86.73
Osprey CC	84.73	3.04	87.78

Plant/Unit	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ADJUSTED ACTUAL ANOHR BTU/KWH
Bartow CC	7,475.1	189.7	7,664.8
Hines 1	7,467.3	-118.9	7,348.4
Hines 2	7,478.4	-37.5	7,440.9
Hines 3	7,249.4	0.6	7,250.0
Hines 4	7,080.0	-54.7	7,025.2
Osprey CC	7,351.0	-14.9	7,336.2

(1) For documentation of adjustments to actual EAF, see sheet 7 of 22.
(2) For documentation of adjustments to actual ANOHR, see sheet 8 of 22.

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO EAF ACTUAL

Duke Energy Florida
January 2020 - December 2020

EAF adjustments for Planned Outage Hours			Bartow CC <u>BA4</u>	Hines 1 <u>HN1</u>	Hines 2 <u>HN2</u>	Hines 3 <u>HN3</u>	Hines 4 <u>HN4</u>	Osprey CC <u>OS1</u>
1	Actual POH	Hrs.	412.55	767.99	1,210.29	0.52	1,057.41	791.00
2	Target POH	Hrs.	180.00	768.00	696.00	336.00	840.00	504.00
3	Adj. Factor (PH-POHT/PH-POHA)		1.03	1.00	1.07	0.96	1.03	1.04
4	Actual EUOH	Hrs.	207.89	501.54	319.35	298.49	316.75	550.09
5	Adj. EUOH (3*4)	Hrs.	213.66	501.54	341.03	287.08	325.66	569.84
6	Actual EAF	%	92.94	85.55	82.59	96.60	84.36	84.73
7	Adjusted EAF (using 2 & 5)	%	95.52	85.55	88.19	92.91	86.73	87.78
8	Difference (7-6)	%	2.58	0.00	5.61	-3.69	2.37	3.04
9	Total adj. to EAF	%	2.58	0.00	5.61	-3.69	2.37	3.04

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO ANOHR ACTUAL

Duke Energy Florida
January 2020 - December 2020

ANOHR adjustments for Target NOF			Bartow CC <u>BA4</u>	Hines 1 <u>HN1</u>	Hines 2 <u>HN2</u>	Hines 3 <u>HN3</u>	Hines 4 <u>HN4</u>	Osprey CC <u>OS1</u>
1	Target NOF	%	72.9	88.0	83.9	80.5	91.7	58.6
2	Target ANOHR	Btu/kwh	7892.1	7260.9	7409.6	7266.2	6981.5	7291.2
3	Actual NOF	%	81.2	80.4	80.1	80.6	82.6	72.3
4	Calc. ANOHR (using 3)	Btu/kwh	7,702.3	7,379.8	7,447.1	7,265.5	7,036.3	7,306.1
5	Total adj. to ANOHR (2-4)	Btu/kwh	189.7	-118.9	-37.5	0.6	-54.7	-14.9

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2020 - December 2020

Unit: Bartow CC

	Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)	
	-----	-----	-----	-----	-----	-----	
****	10	\$1,617,134	92.74	10	\$6,773,688	7,495.6	
	10	\$1,617,134	92.74	9	\$6,096,319	7,527.8	
	9	\$1,455,421	92.29	8	\$5,418,950	7,559.9	
	8	\$1,293,707	91.83	7	\$4,741,581	7,592.1	
	7	\$1,131,994	91.38	6	\$4,064,213	7,624.2	
	6	\$970,280	90.93	5	\$3,386,844	7,656.4	
	5	\$808,567	90.47	4.736	\$3,208,018	7,664.8	****
	4	\$646,854	90.02	4	\$2,709,475	7,688.5	
	3	\$485,140	89.56	3	\$2,032,106	7,720.6	
	2	\$323,427	89.11	2	\$1,354,738	7,752.8	
	1	\$161,713	88.66	1	\$677,369	7,784.9	
		\$0	88.20	0	\$0	7,817.1	
	0	\$0	88.20	0	\$0	7,892.1	
		\$0	88.20	0	\$0	7,967.1	
	-1	(\$266,112)	87.30	-1	(\$677,369)	7,999.2	
	-2	(\$532,225)	86.40	-2	(\$1,354,738)	8,031.4	
	-3	(\$798,337)	85.49	-3	(\$2,032,106)	8,063.5	
	-4	(\$1,064,450)	84.59	-4	(\$2,709,475)	8,095.6	
	-5	(\$1,330,562)	83.69	-5	(\$3,386,844)	8,127.8	
	-6	(\$1,596,675)	82.78	-6	(\$4,064,213)	8,159.9	
	-7	(\$1,862,787)	81.88	-7	(\$4,741,581)	8,192.1	
	-8	(\$2,128,899)	80.98	-8	(\$5,418,950)	8,224.2	
	-9	(\$2,395,012)	80.07	-9	(\$6,096,319)	8,256.4	
	-10	(\$2,661,124)	79.17	-10	(\$6,773,688)	8,288.5	

Equivalent Availability
Weighting Factor:(1)

7.37%

Heat Rate
Weighting Factor:(1)

30.88%

(1) Corrected Weighting Factors, as described in DEF Witness Lewter's March 16, 2021 testimony

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2020 - December 2020

Unit: Hines 1

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)	
-----	-----	-----	-----	-----	-----	
10	\$159,805	89.01	10	\$2,659,112	6,921.9	
9	\$143,825	88.81	9	\$2,393,201	6,948.3	
8	\$127,844	88.61	8	\$2,127,289	6,974.7	
7	\$111,864	88.41	7	\$1,861,378	7,001.1	
6	\$95,883	88.21	6	\$1,595,467	7,027.5	
5	\$79,903	88.01	5	\$1,329,556	7,053.9	
4	\$63,922	87.82	4	\$1,063,645	7,080.3	
3	\$47,942	87.62	3	\$797,734	7,106.7	
2	\$31,961	87.42	2	\$531,822	7,133.1	
1	\$15,981	87.22	1	\$265,911	7,159.5	
	\$0	87.02	0	\$0	7,185.9	
0	\$0	87.02	0	\$0	7,260.9	
	\$0	87.02	0	\$0	7,335.9	
-1	(\$78,466)	86.62	-0.474	(\$126,042)	7,348.4	****
-2	(\$156,933)	86.21	-1	(\$265,911)	7,362.3	
-3	(\$235,399)	85.81	-2	(\$531,822)	7,388.7	
****	-3.647	(\$286,166)	85.55	(\$797,734)	7,415.1	
	-4	(\$313,865)	85.40	(\$1,063,645)	7,441.5	
	-5	(\$392,331)	85.00	(\$1,329,556)	7,467.9	
	-6	(\$470,798)	84.60	(\$1,595,467)	7,494.3	
	-7	(\$549,264)	84.19	(\$1,861,378)	7,520.7	
	-8	(\$627,730)	83.79	(\$2,127,289)	7,547.1	
	-9	(\$706,196)	83.38	(\$2,393,201)	7,573.5	
	-10	(\$784,663)	82.98	(\$2,659,112)	7,600.0	

Equivalent Availability
Weighting Factor:(1)

0.73%

Heat Rate
Weighting Factor:(1)

12.12%

(1) Corrected Weighting Factors, as described in DEF Witness Lewter's March 16, 2021 testimony

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2020 - December 2020

Unit: Hines 2

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)	
-----	-----	-----	-----	-----	-----	
10	\$24,620	91.15	10	\$1,936,965	7,159.2	
9	\$22,158	91.07	9	\$1,743,269	7,176.7	
8	\$19,696	90.98	8	\$1,549,572	7,194.3	
7	\$17,234	90.90	7	\$1,355,876	7,211.8	
6	\$14,772	90.82	6	\$1,162,179	7,229.4	
5	\$12,310	90.74	5	\$968,483	7,246.9	
4	\$9,848	90.65	4	\$774,786	7,264.4	
3	\$7,386	90.57	3	\$581,090	7,282.0	
2	\$4,924	90.49	2	\$387,393	7,299.5	
1	\$2,462	90.40	1	\$193,697	7,317.1	
	\$0	90.32	0	\$0	7,334.6	
0	\$0	90.32	0.000	\$0	7,440.9	
	\$0	90.32	0	\$0	7,409.6	
-1	(\$44,740)	90.15	0	\$0	7,484.6	
-2	(\$89,481)	89.98	-1	(\$193,697)	7,502.2	
-3	(\$134,221)	89.80	-2	(\$387,393)	7,519.7	
-4	(\$178,962)	89.63	-3	(\$581,090)	7,537.2	
-5	(\$223,702)	89.46	-4	(\$774,786)	7,554.8	
-6	(\$268,442)	89.29	-5	(\$968,483)	7,572.3	
-7	(\$313,183)	89.12	-6	(\$1,162,179)	7,589.9	
-8	(\$357,923)	88.95	-7	(\$1,355,876)	7,607.4	
-9	(\$402,664)	88.77	-8	(\$1,549,572)	7,625.0	
-10	(\$447,404)	88.60	-9	(\$1,743,269)	7,642.5	
****	-10	(\$447,404)	88.60	-10	(\$1,936,965)	7,660.0

Equivalent Availability
Weighting Factor:(1)

0.11%

Heat Rate
Weighting Factor:(1)

8.83%

(1) Corrected Weighting Factors, as described in DEF Witness Lewter's March 16, 2021 testimony

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2020 - December 2020

Unit: Hines 3

	Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)	
	10	\$158,699	94.89	10	\$2,088,568	7,018.6	
	9	\$142,829	94.77	9	\$1,879,711	7,035.9	
	8	\$126,959	94.66	8	\$1,670,854	7,053.1	
	7	\$111,089	94.54	7	\$1,461,997	7,070.4	
	6	\$95,219	94.43	6	\$1,253,141	7,087.6	
	5	\$79,349	94.31	5	\$1,044,284	7,104.9	
	4	\$63,479	94.19	4	\$835,427	7,122.1	
	3	\$47,610	94.08	3	\$626,570	7,139.4	
	2	\$31,740	93.96	2	\$417,714	7,156.6	
	1	\$15,870	93.85	1	\$208,857	7,173.9	
		\$0	93.73	0	\$0	7,191.2	
	0	\$0	93.73	0.000	\$0	7,250.0	****
		\$0	93.73	0	\$0	7,266.2	
	-1	(\$72,598)	93.50	0	\$0	7,341.2	
	-2	(\$145,197)	93.26	-1	(\$208,857)	7,358.4	
	-3	(\$217,795)	93.02	-2	(\$417,714)	7,375.7	
****	-3.468	(\$251,771)	92.91	-3	(\$626,570)	7,392.9	
	-4	(\$290,393)	92.78	-4	(\$835,427)	7,410.2	
	-5	(\$362,991)	92.54	-5	(\$1,044,284)	7,427.4	
	-6	(\$435,590)	92.30	-6	(\$1,253,141)	7,444.7	
	-7	(\$508,188)	92.06	-7	(\$1,461,997)	7,461.9	
	-8	(\$580,786)	91.83	-8	(\$1,670,854)	7,479.2	
	-9	(\$653,384)	91.59	-9	(\$1,879,711)	7,496.4	
	-10	(\$725,983)	91.35	-10	(\$2,088,568)	7,513.7	

Equivalent Availability
Weighting Factor:(1)

0.72%

Heat Rate
Weighting Factor:(1)

9.52%

(1) Corrected Weighting Factors, as described in DEF Witness Lewter's March 16, 2021 testimony

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2020 - December 2020

Unit: Hines 4

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)
-----	-----	-----	-----	-----	-----
10	\$866,344	87.02	10	\$1,610,787	6,801.1
9.065	\$785,341	86.73	9	\$1,449,708	6,811.7
9	\$779,709	86.71	8	\$1,288,630	6,822.2
8	\$693,075	86.40	7	\$1,127,551	6,832.8
7	\$606,441	86.10	6	\$966,472	6,843.3
6	\$519,806	85.79	5	\$805,393	6,853.8
5	\$433,172	85.49	4	\$644,315	6,864.4
4	\$346,537	85.18	3	\$483,236	6,874.9
3	\$259,903	84.87	2	\$322,157	6,885.5
2	\$173,269	84.57	1	\$161,079	6,896.0
1	\$86,634	84.26	0	\$0	6,906.5
	\$0	83.95	0.000	\$0	7,025.2 ****
0	\$0	83.95	0	\$0	6,981.5
	\$0	83.95	0	\$0	7,056.5
-1	(\$219,873)	83.32	-1	(\$161,079)	7,067.1
-2	(\$439,746)	82.68	-2	(\$322,157)	7,077.6
-3	(\$659,619)	82.05	-3	(\$483,236)	7,088.1
-4	(\$879,491)	81.41	-4	(\$644,315)	7,098.7
-5	(\$1,099,364)	80.78	-5	(\$805,393)	7,109.2
-6	(\$1,319,237)	80.14	-6	(\$966,472)	7,119.8
-7	(\$1,539,110)	79.51	-7	(\$1,127,551)	7,130.3
-8	(\$1,758,983)	78.87	-8	(\$1,288,630)	7,140.8
-9	(\$1,978,856)	78.24	-9	(\$1,449,708)	7,151.4
-10	(\$2,198,729)	77.60	-10	(\$1,610,787)	7,161.9

Equivalent Availability
Weighting Factor:(1)

3.95%

Heat Rate
Weighting Factor:(1)

7.34%

(1) Corrected Weighting Factors, as described in DEF Witness Lewter's March 16, 2021 testimony

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2020 - December 2020

Unit: Osprey CC

	Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (1) (\$)	Average Heat Rate (1) (BTU/KWH)
	10	\$521,293	91.02	10	\$3,516,776	6,716.5
	9	\$469,164	90.73	9	\$3,165,098	6,766.5
	8	\$417,035	90.45	8	\$2,813,421	6,816.5
	7	\$364,905	90.16	7	\$2,461,743	6,866.4
	6	\$312,776	89.87	6	\$2,110,066	6,916.4
	5	\$260,647	89.58	5	\$1,758,388	6,966.4
	4	\$208,517	89.29	4	\$1,406,710	7,016.3
	3	\$156,388	89.01	3	\$1,055,033	7,066.3
	2	\$104,259	88.72	2	\$703,355	7,116.3
	1	\$52,129	88.43	1	\$351,678	7,166.3
		\$0	88.14	0	\$0	7,216.2
	0	\$0	88.14	0.000	\$0	7,336.2
		\$0	88.14	0	\$0	7,291.2
****	-0.621	(\$70,569)	87.77	0	\$0	7,366.2
	-1	(\$113,638)	87.55	-1	(\$351,678)	7,416.2
	-2	(\$227,276)	86.96	-2	(\$703,355)	7,466.2
	-3	(\$340,915)	86.37	-3	(\$1,055,033)	7,516.1
	-4	(\$454,553)	85.78	-4	(\$1,406,710)	7,566.1
	-5	(\$568,191)	85.19	-5	(\$1,758,388)	7,616.1
	-6	(\$681,829)	84.60	-6	(\$2,110,066)	7,666.0
	-7	(\$795,467)	84.01	-7	(\$2,461,743)	7,716.0
	-8	(\$909,106)	83.42	-8	(\$2,813,421)	7,766.0
	-9	(\$1,022,744)	82.82	-9	(\$3,165,098)	7,816.0
	-10	(\$1,136,382)	82.23	-10	(\$3,516,776)	7,865.9

Equivalent Availability
Weighting Factor:(1)

2.38%

Heat Rate
Weighting Factor:(1)

16.03%

(1) Corrected Weighting Factors, Fuel Savings/Loss and Average Heat Rate ranges as described
in DEF Witness Lewter's March 16, 2021 testimony

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Bartow CC	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-Dec Period
1. EAF	83.93	99.00	94.62	95.42	98.18	100.00	99.70	99.14	99.78	99.34	94.76	52.35	92.94
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	615.8	621.1	661.0	549.1	654.2	691.9	742.6	730.4	669.5	699.5	566.6	339.5	7,130.4
4. RSH	8.6	69.0	43.2	137.9	78.5	28.1	0.1	7.2	49.0	39.6	116.7	50.0	627.8
5. UH	119.6	5.9	38.9	33.0	11.4	0.0	1.3	6.4	1.6	4.9	37.8	354.5	615.2
6. POH	119.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	259.3	412.6
7. FOH	0.4	5.7	34.5	1.7	0.0	0.0	1.3	6.4	1.6	4.9	3.7	95.2	155.4
8. MOH	0.0	0.3	4.4	31.3	11.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	47.2
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PFOH	0.0	11.2	11.4	0.0	0.1	0.0	19.9	0.0	0.0	0.0	0.0	0.0	42.6
12. LR PF (MW)	0.0	108.2	108.2	0.0	105.5	0.0	55.3	0.0	0.0	0.0	0.0	0.0	83.4
13. PMOH	0.0	0.0	0.0	0.0	21.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.7
14. LR PM (MW)	0.0	0.0	0.0	0.0	114.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	114.2
15. NSC (MW)	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
16. OPER MBTU	4,050,994	4,286,777	4,724,966	3,333,386	4,344,128	4,836,805	5,246,371	5,034,287	4,527,059	4,927,283	3,459,135	736,103	49,507,294
17. NET GEN (MWH)	555,214	552,497	602,801	443,687	577,023	653,418	715,825	685,700	612,742	666,148	459,555	98,348	6,622,958
18. ANOHR (BTU/KWH)	7,296.3	7,758.9	7,838.4	7,512.9	7,528.5	7,402.3	7,329.1	7,341.8	7,388.2	7,396.7	7,527.1	7,484.7	7,475.1
19. NOF (%)	78.81	77.75	79.72	70.64	77.11	82.55	84.26	82.06	80.01	83.25	75.25	69.24	81.19
20. NPC (MW)	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
ANOHR EQUATION:	ANOHR=	-22.758	x NOF +	9,550.10									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 1	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-Dec Period
1. EAF	98.88	88.34	95.76	82.92	93.59	73.83	100.00	98.12	98.74	6.93	89.74	100.00	85.55
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	259.0	575.2	654.6	573.3	632.1	531.6	744.0	710.2	688.9	3.6	647.0	744.0	6,763.5
4. RSH	476.7	42.3	57.4	24.0	64.3	0.0	0.0	19.8	23.6	48.0	0.0	0.0	756.0
5. UH	8.3	78.5	31.0	122.7	47.7	188.4	0.0	14.0	7.5	692.4	74.0	0.0	1,264.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	692.4	74.0	0.0	766.4
7. FOH	8.3	61.4	31.0	1.7	11.4	188.4	0.0	1.7	0.0	0.0	0.0	0.0	303.9
8. MOH	0.0	17.1	0.0	121.0	36.3	0.0	0.0	12.3	7.5	0.0	0.0	0.0	194.2
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.3	0.0	0.0	0.0	11.3
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.8	0.0	0.0	0.0	68.8
11. PFOH	0.0	16.6	5.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.7
12. LR PF (MW)	0.0	77.0	49.5	82.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	71.6
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
16. OPER MBTU	780,815	1,648,431	1,880,686	1,642,991	1,823,994	1,556,416	2,249,479	2,047,183	1,993,767	6,060	1,815,239	2,463,886	19,908,947
17. NET GEN (MWH)	102,818	215,761	250,559	219,501	240,760	205,204	300,649	275,796	262,778	316	245,508	346,508	2,666,158
18. ANOHR (BTU/KWH)	7,594.1	7,640.1	7,506.0	7,485.1	7,576.0	7,584.7	7,482.1	7,422.8	7,587.3	19,178.0	7,393.8	7,110.6	7,467.3
19. NOF (%)	81.02	76.55	78.12	78.13	77.74	78.78	82.47	79.25	77.84	18.01	77.44	95.05	80.45
20. NPC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
ANOHR EQUATION:	ANOHR=	-15.806	x NOF +	8,651.35									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 2	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-Dec Period
1. EAF	100.00	94.56	0.00	29.43	81.90	86.67	99.97	99.96	99.92	100.00	98.76	100.00	82.59
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	703.6	559.2	0.0	246.4	578.7	623.3	744.0	744.0	671.6	709.7	639.9	634.0	6,854.4
4. RSH	40.5	99.0	0.0	12.9	40.2	17.2	0.0	0.0	48.4	34.3	78.9	110.0	481.2
5. UH	0.0	37.9	743.0	460.6	125.1	79.5	0.0	0.0	0.0	0.0	2.3	0.0	1,448.4
6. POH	0.0	24.2	743.0	442.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,209.5
7. FOH	0.0	6.9	0.0	18.3	26.1	26.3	0.0	0.0	0.0	0.0	2.3	0.0	79.8
8. MOH	0.0	6.8	0.0	0.0	99.0	53.2	0.0	0.0	0.0	0.0	0.0	0.0	159.1
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	5.0	0.0	0.0	0.0	7.0
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	63.2	0.0	59.5	0.0	0.0	0.0	60.6
11. PFOH	0.0	0.0	0.0	165.1	41.7	91.1	0.0	1.2	0.0	0.0	47.9	0.0	346.9
12. LR PF (MW)	0.0	0.0	0.0	150.2	120.1	94.7	0.0	137.1	0.0	0.0	72.8	0.0	121.3
13. PMOH	0.0	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4
14. LR PM (MW)	0.0	0.0	0.0	65.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.1
15. NSC (MW)	524	524	524	524	524	524	524	524	524	524	524	524	524
16. OPER MBTU	2,149,462	1,871,576	0	682,347	1,638,690	1,955,733	2,438,251	2,356,982	2,088,637	2,347,799	1,964,082	2,033,845	21,527,405
17. NET GEN (MWH)	290,864	252,437	0	89,489	214,825	257,381	324,395	317,245	279,715	317,919	261,788	272,556	2,878,614
18. ANOHR (BTU/KWH)	7,389.9	7,414.0	0.0	7,624.9	7,628.0	7,598.6	7,516.3	7,429.5	7,467.0	7,384.9	7,502.6	7,462.1	7,478.4
19. NOF (%)	78.90	86.15	0.00	69.30	70.84	78.80	83.21	81.37	79.48	85.49	78.08	82.04	80.15
20. NPC (MW)	524	524	524	524	524	524	524	524	524	524	524	524	524
ANOHR EQUATION:	ANOHR=	-10.130	x NOF +	8,259.03									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 3	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-Dec Period
1. EAF	100.00	99.52	100.00	99.65	77.43	99.65	94.83	92.04	100.00	99.94	96.57	100.00	96.60
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	460.1	460.2	726.7	656.0	521.0	714.9	678.2	657.6	633.6	725.2	612.8	652.4	7,498.6
4. RSH	284.0	233.0	16.3	61.5	55.1	3.1	28.8	27.2	86.4	18.7	83.5	91.6	989.0
5. UH	0.0	2.8	0.0	2.5	167.9	2.0	37.1	59.2	0.0	0.1	24.7	0.0	296.4
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	2.8	0.0	0.0	54.8	2.0	25.5	55.2	0.0	0.1	0.0	0.0	140.5
8. MOH	0.0	0.0	0.0	2.5	113.1	0.0	11.6	4.0	0.0	0.0	24.7	0.0	155.9
9. PPOH	0.0	0.0	0.0	0.0	0.0	1.3	1.0	0.0	0.0	4.0	0.0	0.0	6.3
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	51.4	56.2	0.0	0.0	35.9	0.0	0.0	42.4
11. PFOH	0.0	4.0	0.0	0.0	0.0	2.0	7.4	0.0	0.0	0.0	0.0	0.0	13.5
12. LR PF (MW)	0.0	61.6	0.0	0.0	0.0	88.1	88.7	0.0	0.0	0.0	0.0	0.0	80.6
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15. NSC (MW)	515	515	515	515	515	515	515	515	515	515	515	515	515
16. OPER MBTU	1,364,781	1,411,103	2,170,967	1,926,864	1,459,758	2,191,328	2,044,783	1,974,022	1,869,332	2,326,090	1,798,283	2,016,270	22,553,582
17. NET GEN (MWH)	181,972	196,056	299,188	266,592	197,411	307,369	281,736	265,713	258,487	326,980	247,938	281,660	3,111,102
18. ANOHR (BTU/KWH)	7,499.9	7,197.5	7,256.2	7,227.8	7,394.5	7,129.3	7,257.8	7,429.2	7,231.8	7,113.9	7,253.0	7,158.5	7,249.4
19. NOF (%)	76.81	82.72	79.95	78.92	73.57	83.48	80.67	78.47	79.21	87.55	78.56	83.83	80.56
20. NPC (MW)	515	515	515	515	515	515	515	515	515	515	515	515	515
ANOHR EQUATION:	ANOHR=	-18.685	x NOF +	8,770.80									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 4	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-Dec Period
1. EAF	99.14	100.00	94.34	94.07	99.85	100.00	83.67	90.96	99.44	98.64	17.61	34.81	84.36
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	720.9	648.9	663.2	556.2	697.4	720.0	618.7	654.7	696.7	728.4	72.3	224.3	7,001.6
4. RSH	17.6	47.1	38.2	121.2	46.6	0.0	3.8	22.0	23.3	5.5	54.7	34.8	414.7
5. UH	5.6	0.0	41.7	42.6	0.0	0.0	121.5	67.3	0.0	10.1	594.0	485.0	1,367.7
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	594.0	462.3	1,056.3
7. FOH	5.6	0.0	41.7	42.6	0.0	0.0	121.5	67.3	0.0	10.1	0.0	22.7	311.4
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	0.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0
10. LR PP (MW)	0.0	0.0	0.0	0.0	63.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.1
11. PFOH	5.6	0.0	3.0	0.6	0.0	0.0	0.0	0.0	14.1	0.0	0.0	0.0	23.2
12. LR PF (MW)	78.1	0.0	62.4	89.0	0.0	0.0	0.0	0.0	62.0	0.0	0.0	0.0	66.6
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	14.0
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	87.0	0.0	0.0	0.0	87.0
15. NSC (MW)	516	516	516	516	516	516	516	516	516	516	516	516	516
16. OPER MBTU	2,200,579	1,936,502	1,918,280	1,634,032	2,088,963	2,248,109	1,886,386	1,930,518	2,072,197	2,373,395	226,338	614,721	21,130,019
17. NET GEN (MWH)	317,533	278,017	267,248	228,911	295,448	317,783	264,962	272,211	289,926	334,914	31,514	86,004	2,984,471
18. ANOHR (BTU/KWH)	6,930.2	6,965.4	7,177.9	7,138.3	7,070.5	7,074.4	7,119.5	7,092.0	7,147.3	7,086.6	7,182.1	7,147.6	7,080.0
19. NOF (%)	85.37	83.03	78.10	79.76	82.10	85.54	82.99	80.58	80.65	89.11	84.47	74.33	82.61
20. NPC (MW)	516	516	516	516	516	516	516	516	516	516	516	516	516
ANOHR EQUATION:	ANOHR=	-6.017	x NOF +	7,533.33									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Osprey CC	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-Dec Period
1. EAF	99.53	96.55	0.00	54.31	100.00	100.00	100.00	99.45	98.44	98.11	98.51	72.92	84.73
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	194.4	47.3	0.0	286.4	650.7	644.9	672.7	662.1	637.5	675.5	648.9	509.5	5,629.9
4. RSH	546.7	624.7	0.0	104.6	93.3	75.1	71.3	81.9	82.0	65.5	72.1	55.9	1,873.1
5. UH	2.8	24.0	743.0	329.0	0.0	0.0	0.0	0.0	0.5	3.1	0.0	178.6	1,281.0
6. POH	0.0	24.0	743.0	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	791.0
7. FOH	0.6	0.0	0.0	305.0	0.0	0.0	0.0	0.0	0.5	3.1	0.0	3.5	312.7
8. MOH	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	175.1	177.3
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PFOH	3.5	0.0	0.0	0.0	0.0	0.0	0.0	130.6	339.4	347.7	339.9	266.4	1,427.6
12. LR PF (MW)	111.3	0.0	0.0	0.0	0.0	0.0	0.0	18.4	18.4	18.4	18.4	49.9	24.5
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15. NSC (MW)	582	582	582	582	582	582	582	582	582	582	582	582	582
16. OPER MBTU	541,636	110,673	0	790,816	2,063,929	2,031,821	2,147,031	2,088,278	1,939,717	2,127,754	2,022,465	1,555,299	17,419,420
17. NET GEN (MWH)	71,968	14,619	0	93,205	282,305	276,486	292,433	284,360	267,137	292,801	279,430	214,912	2,369,656
18. ANOHR (BTU/KWH)	7,526.1	7,570.5	0.0	8,484.7	7,311.0	7,348.7	7,342.0	7,343.8	7,261.1	7,266.9	7,237.8	7,236.9	7,351.0
19. NOF (%)	63.60	53.12	0.00	55.91	74.55	73.67	74.69	73.79	72.00	74.48	73.99	72.48	72.32
20. NPC (MW)	582	582	582	582	582	582	582	582	582	582	582	582	582
ANOHR EQUATION: (1) ANOHR= 1.086 x NOF + 7,227.56													

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(1) Corrected ANOHR equation, as described in DEF Witness Lewter's March 16, 2021 testimony

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PLANNED OUTAGE SCHEDULES
ACTUAL

Duke Energy Florida
January 2020 - December 2020

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow CC	01/01 (0000) - 01/29 (1139)	4B: Major GasTurbine Overhaul; Fas Fuel System with Controls and Instrumentation
Bartow CC	11/28 (0014) - 12/13 (1040)	4A: Gas Turbine - Boroscope Inspection
Bartow CC	11/28 (0054) - 12/23 (0558)	4S: Inspection
Bartow CC	12/12 (2340) - 12/23 (2123)	4C:Gas Turbine - Boroscope Inspection
Hines 1	10/03 (0000) - 11/04 (1337)	General Gas Turbine Unit Inspection, Exciter Commutator & Brushes, Gas Fuel System w/ Controls & Instruments
Hines 2	02/28 (2343) - 04/19 (1317)	General Gas Turbine Unit Inspection
Hines 4	11/06 (0600) - 12/23 (1349)	Gas & Steam Turbine Control Systems - Upgrades
Osprey CC	02/29 (0000) - 04/02 (0000)	General Gas Turbine Unit & Boroscope Inspection

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Planned Outage Schedule - Actual												
January 2020 - December 2020												Duke Energy Florida
	January	February	March	April	May	June	July	August	September	October	November	December
Bartow CC	Major Gas Turbine Overhaul 1/29 28 days										Gas & Steam Turbine Inspection 11/28 26 days	12/23
Hines 1									General Gas Turbine Inspection 10/3 33 days	11/4		
Hines 2			General Gas Turbine Unit Inspection 2/28 51 days	4/19								
Hines 3												
Hines 4										Gas & Steam Turbine Control Systems - Upgrade 11/6 47 days	12/23	
Osprey CC		General Gas Turbine & Boroscope Inspection 2/29 33 days	4/2									

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GPIF Targets and Ranges for January through December 2022

STANDARD FORM GPIF SCHEDULES

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GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Duke Energy Florida
Period of: January 2022 - December 2022

Generating Performance Incentive Points (GPIF) -----	Fuel Saving/Loss (\$) -----	Generating Performance Incentive Factor (\$) -----
10	\$35,296,962	\$17,648,481
9	\$31,767,266	\$15,883,633
8	\$28,237,570	\$14,118,785
7	\$24,707,873	\$12,353,937
6	\$21,178,177	\$10,589,089
5	\$17,648,481	\$8,824,241
4	\$14,118,785	\$7,059,392
3	\$10,589,089	\$5,294,544
2	\$7,059,392	\$3,529,696
1	\$3,529,696	\$1,764,848
0	\$0	\$0
-1	(\$4,382,269)	(\$1,764,848)
-2	(\$8,764,538)	(\$3,529,696)
-3	(\$13,146,808)	(\$5,294,544)
-4	(\$17,529,077)	(\$7,059,392)
-5	(\$21,911,346)	(\$8,824,241)
-6	(\$26,293,615)	(\$10,589,089)
-7	(\$30,675,885)	(\$12,353,937)
-8	(\$35,058,154)	(\$14,118,785)
-9	(\$39,440,423)	(\$15,883,633)
-10	(\$43,822,692)	(\$17,648,481)

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GENERATION PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

EST MATED

Duke Energy Florida
Period of: January 2022 - December 2022

1	Beginning of period balance of common equity	\$8,317,690,360
	END OF MONTH BALANCE OF COMMON EQUITY:	
2	Month of JANUARY 2022	\$8,371,359,567
3	Month of FEBRUARY 2022	\$8,412,850,600
4	Month of MARCH 2022	\$8,452,445,947
5	Month of APRIL 2022	\$8,499,186,827
6	Month of MAY 2022	\$8,578,530,814
7	Month of JUNE 2022	\$8,678,262,412
8	Month of JULY 2022	\$8,795,911,286
9	Month of AUGUST 2022	\$8,742,271,300
10	Month of SEPTEMBER 2022	\$8,849,497,189
11	Month of OCTOBER 2022	\$8,928,970,986
12	Month of NOVEMBER 2022	\$8,984,197,254
13	Month of DECEMBER 2022	\$9,066,949,193
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	\$8,667,547,979
15	25 Basis Points	0.0025
16	Revenue Expansion Factor	74.4555%
17	Maximum allowed incentive dollars (LINE 14 times LINE 15 divided by LINE 16)	\$29,103,135
18	Jurisdictional Sales	39,355,059 MWH
19	Total Sales	39,372,209 MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	99.96%
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	\$29,091,493
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 7.101.1	\$17,648,481
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	\$17,648,481

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GPIF TARGET AND RANGE SUMMARY

Duke Energy Florida
Period of: January 2022 - December 2022

Plant/Unit	Weighting	EA	EA RANGE		Max. Fuel	Max. Fuel
	Factor	Target	Max.	Min.	Savings	Loss
	(%)	(%)	(%)	(%)	(\$000)	(\$000)
Bartow 4	0.54	82.04	85.08	75.83	191	(1,689)
Crystal River 4	19.40	69.57	78.31	52.46	6,846	(11,103)
Crystal River 5	10.52	74.10	79.02	64.29	3,714	(5,719)
Hines 1	0.86	89.40	91.66	84.90	304	(509)
Hines 2	0.55	89.32	89.84	88.26	194	(97)
Hines 3	0.48	93.62	94.82	91.14	168	(403)
Hines 4	0.57	85.09	86.44	82.24	201	(625)
GPIF System	32.92				11,620	(20,146)

Plant/Unit	Weighting	ANOHR Target	NOF	ANOHR RANGE		Max. Fuel	Max. Fuel
	Factor	(BTU/KWH)		Min.	Max.	Savings	Loss
	(%)	(BTU/KWH)		(BTU/KWH)	(BTU/KWH)	(\$000)	(\$000)
Bartow 4	19.09	7,758	67.5	7,441	8,075	6,738	(6,738)
Crystal River 4	16.46	9,472	92.3	8,963	9,980	5,809	(5,809)
Crystal River 5	16.70	9,802	80.0	9,208	10,397	5,895	(5,895)
Hines 1	2.67	7,705	67.5	7,538	7,871	944	(944)
Hines 2	2.13	7,550	71.7	7,436	7,664	751	(751)
Hines 3	4.68	7,394	70.6	7,219	7,570	1,653	(1,653)
Hines 4	5.35	7,057	81.5	6,878	7,237	1,888	(1,888)
GPIF System	67.08					23,677	(23,677)

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE AVAILABILITY

Duke Energy Florida
Period of: January 2022 - December 2022

Plant/Unit	Target	Norm.	Target			Actual Performance			Actual Performance		
	Wt.	Wt.				1st Prior Period			2nd Prior Period		
	Factor	Factor	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Bartow 4	0.54	1.65	11.51	6.45	6.45	2.45	18.35	19.41	4.70	2.37	2.68
Crystal River 4	19.40	58.92	11.51	18.92	21.65	0.00	54.28	54.28	35.83	7.60	16.45
Crystal River 5	10.52	31.97	15.34	10.56	12.57	0.00	8.18	8.38	11.59	3.44	5.50
Hines 1	0.86	2.62	5.75	4.84	7.26	33.16	5.37	8.31	8.73	5.71	6.91
Hines 2	0.55	1.67	9.59	1.09	1.73	0.00	0.07	0.08	13.77	3.64	4.50
Hines 3	0.48	1.45	3.84	2.54	2.84	66.28	3.53	17.41	0.00	3.40	3.83
Hines 4	0.57	1.73	12.05	2.86	3.30	0.00	0.74	0.85	12.03	3.63	4.36
GPIF System											
Wghtd. Avg.	32.92	100.00	12.45	14.86	17.20	1.87	35.10	35.46	25.56	5.93	11.88

Plant/Unit	Actual Performance			Actual Performance			Actual Performance		
	3rd Prior Period			4th Prior Period			5th Prior Period		
	Jan-Dec 2019			Jan-Dec 2018			Jan-Dec 2017		
	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Bartow 4	16.42	1.89	2.39	1.86	6.00	6.33	1.43	10.97	11.43
Crystal River 4	5.75	8.41	11.12	12.23	6.20	7.73	0.00	16.97	16.97
Crystal River 5	27.65	13.16	22.61	4.01	8.92	9.30	19.56	5.13	6.37
Hines 1	6.29	6.62	7.87	6.68	3.56	4.23	7.71	3.08	3.57
Hines 2	3.78	0.22	0.25	5.03	1.52	1.78	7.93	0.61	0.74
Hines 3	6.31	0.85	1.06	8.59	0.90	1.10	7.18	4.93	5.68
Hines 4	9.31	3.38	3.93	6.71	1.28	1.51	9.04	2.01	2.34
GPIF System									
Wghtd. Avg.	12.98	9.44	14.11	9.02	6.76	7.82	6.87	12.01	12.45

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE
AVERAGE NET OPERATING HEAT RATE

Duke Energy Florida
Period of: January 2022 - December 2022

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan 2020 - Dec 2020	2nd Prior HR Jan 2019 - Dec 2019	3rd Prior HR Jan 2018 - Dec 2018
Bartow 4	19.09	28.46	7,758	7,636	7,861	7,873
Crystal River 4	16.46	24.53	9,472	9,573	9,318	9,488
Crystal River 5	16.70	24.90	9,802	9,866	9,537	9,872
Hines 1	2.67	3.99	7,705	7,727	7,694	7,752
Hines 2	2.13	3.17	7,550	7,564	7,542	7,506
Hines 3	4.68	6.98	7,394	7,391	7,385	7,427
Hines 4	5.35	7.98	7,057	7,102	7,037	7,025
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
GPIF System						
Weighted Avg.	67.08	100.00	8,597	8,608	8,520	8,652

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DERIVATION OF WEIGHTING FACTORS

Duke Energy Florida
Period of: January 2022 - December 2022

Unit Performance Indicator	Production Costing Simulation Fuel Cost (\$000)			Weighting Factor (% of Savings)
	At Target (1)	At Maximum Improvement (2)	Savings (3)	
Bartow 4 EAF	1,902,201	1,902,010	191	0.54
Bartow 4 HR	1,902,201	1,895,463	6,738	19.09
Crystal River 4 EAF	1,902,201	1,895,355	6,846	19.40
Crystal River 4 HR	1,902,201	1,896,392	5,809	16.46
Crystal River 5 EAF	1,902,201	1,898,487	3,714	10.52
Crystal River 5 HR	1,902,201	1,896,306	5,895	16.70
Hines 1 EAF	1,902,201	1,901,897	304	0.86
Hines 1 HR	1,902,201	1,901,257	944	2.67
Hines 2 EAF	1,902,201	1,902,006	194	0.55
Hines 2 HR	1,902,201	1,901,450	751	2.13
Hines 3 EAF	1,902,201	1,902,033	168	0.48
Hines 3 HR	1,902,201	1,900,548	1,653	4.68
Hines 4 EAF	1,902,201	1,902,000	201	0.57
Hines 4 HR	1,902,201	1,900,313	1,888	5.35

1. Fuel Adjustment Base Case - all unit performance indicators at Target.
2. All other unit performance indicators at Target.
3. Expressed in replacement costs.

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INCENTIVE POINTS TABLES

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2022 - December 2022

Bartow 4

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)
10	\$191,204	85.08	10	\$6,737,723	7,441.0
9	\$172,083	84.77	9	\$6,063,951	7,465.2
8	\$152,963	84.47	8	\$5,390,178	7,489.4
7	\$133,843	84.17	7	\$4,716,406	7,513.6
6	\$114,722	83.86	6	\$4,042,634	7,537.8
5	\$95,602	83.56	5	\$3,368,861	7,562.0
4	\$76,481	83.26	4	\$2,695,089	7,586.2
3	\$57,361	82.95	3	\$2,021,317	7,610.4
2	\$38,241	82.65	2	\$1,347,545	7,634.5
1	\$19,120	82.35	1	\$673,772	7,658.7
					7,682.9
0	\$0	82.04	0	\$0	7,757.9
					7,832.9
-1	(\$168,908)	81.42	-1	(\$673,772)	7,857.1
-2	(\$337,817)	80.80	-2	(\$1,347,545)	7,881.3
-3	(\$506,725)	80.18	-3	(\$2,021,317)	7,905.5
-4	(\$675,634)	79.56	-4	(\$2,695,089)	7,929.7
-5	(\$844,542)	78.93	-5	(\$3,368,861)	7,953.9
-6	(\$1,013,451)	78.31	-6	(\$4,042,634)	7,978.1
-7	(\$1,182,359)	77.69	-7	(\$4,716,406)	8,002.2
-8	(\$1,351,268)	77.07	-8	(\$5,390,178)	8,026.4
-9	(\$1,520,176)	76.45	-9	(\$6,063,951)	8,050.6
-10	(\$1,689,084)	75.83	-10	(\$6,737,723)	8,074.8

Equivalent Availability
Weighting Factor:

0.54%

Heat Rate
Weighting Factor:

19.09%

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Original Sheet No. 7.106.2

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2022 - December 2022

Crystal River 4

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)
10	\$6,845,968	78.31	10	\$5,808,668	8,963.3
9	\$6,161,371	77.43	9	\$5,227,802	9,006.6
8	\$5,476,774	76.56	8	\$4,646,935	9,049.9
7	\$4,792,177	75.69	7	\$4,066,068	9,093.3
6	\$4,107,581	74.81	6	\$3,485,201	9,136.6
5	\$3,422,984	73.94	5	\$2,904,334	9,179.9
4	\$2,738,387	73.07	4	\$2,323,467	9,223.3
3	\$2,053,790	72.19	3	\$1,742,601	9,266.6
2	\$1,369,194	71.32	2	\$1,161,734	9,309.9
1	\$684,597	70.44	1	\$580,867	9,353.2
					9,396.6
0	\$0	69.57	0	\$0	9,471.6
					9,546.6
-1	(\$1,110,321)	67.86	-1	(\$580,867)	9,589.9
-2	(\$2,220,641)	66.15	-2	(\$1,161,734)	9,633.2
-3	(\$3,330,962)	64.44	-3	(\$1,742,601)	9,676.6
-4	(\$4,441,282)	62.73	-4	(\$2,323,467)	9,719.9
-5	(\$5,551,603)	61.02	-5	(\$2,904,334)	9,763.2
-6	(\$6,661,923)	59.31	-6	(\$3,485,201)	9,806.5
-7	(\$7,772,244)	57.60	-7	(\$4,066,068)	9,849.9
-8	(\$8,882,564)	55.89	-8	(\$4,646,935)	9,893.2
-9	(\$9,992,885)	54.17	-9	(\$5,227,802)	9,936.5
-10	(\$11,103,205)	52.46	-10	(\$5,808,668)	9,979.9

Equivalent Availability
Weighting Factor:

19.40%

Heat Rate
Weighting Factor:

16.46%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2022 - December 2022

Crystal River 5

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)
10	\$3,714,442	79.02	10	\$5,894,687	9,207.6
9	\$3,342,998	78.53	9	\$5,305,219	9,259.5
8	\$2,971,554	78.03	8	\$4,715,750	9,311.5
7	\$2,600,110	77.54	7	\$4,126,281	9,363.5
6	\$2,228,665	77.05	6	\$3,536,812	9,415.4
5	\$1,857,221	76.56	5	\$2,947,344	9,467.4
4	\$1,485,777	76.07	4	\$2,357,875	9,519.3
3	\$1,114,333	75.58	3	\$1,768,406	9,571.3
2	\$742,888	75.08	2	\$1,178,937	9,623.2
1	\$371,444	74.59	1	\$589,469	9,675.2
					9,727.2
0	\$0	74.10	0	\$0	9,802.2
					9,877.2
-1	(\$571,906)	73.12	-1	(\$589,469)	9,929.1
-2	(\$1,143,812)	72.14	-2	(\$1,178,937)	9,981.1
-3	(\$1,715,717)	71.16	-3	(\$1,768,406)	10,033.0
-4	(\$2,287,623)	70.18	-4	(\$2,357,875)	10,085.0
-5	(\$2,859,529)	69.19	-5	(\$2,947,344)	10,136.9
-6	(\$3,431,435)	68.21	-6	(\$3,536,812)	10,188.9
-7	(\$4,003,340)	67.23	-7	(\$4,126,281)	10,240.8
-8	(\$4,575,246)	66.25	-8	(\$4,715,750)	10,292.8
-9	(\$5,147,152)	65.27	-9	(\$5,305,219)	10,344.8
-10	(\$5,719,058)	64.29	-10	(\$5,894,687)	10,396.7

Equivalent Availability
Weighting Factor:

10.52%

Heat Rate
Weighting Factor:

16.70%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2022 - December 2022

Hines 1

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)
10	\$304,312	91.66	10	\$943,538	7,538.1
9	\$273,880	91.43	9	\$849,184	7,547.3
8	\$243,449	91.21	8	\$754,831	7,556.4
7	\$213,018	90.98	7	\$660,477	7,565.5
6	\$182,587	90.76	6	\$566,123	7,574.7
5	\$152,156	90.53	5	\$471,769	7,583.8
4	\$121,725	90.31	4	\$377,415	7,593.0
3	\$91,293	90.08	3	\$283,061	7,602.1
2	\$60,862	89.86	2	\$188,708	7,611.2
1	\$30,431	89.63	1	\$94,354	7,620.4
					7,629.5
0	\$0	89.40	0	\$0	7,704.5
					7,779.5
-1	(\$50,919)	88.95	-1	(\$94,354)	7,788.6
-2	(\$101,838)	88.50	-2	(\$188,708)	7,797.8
-3	(\$152,757)	88.05	-3	(\$283,061)	7,806.9
-4	(\$203,675)	87.60	-4	(\$377,415)	7,816.1
-5	(\$254,594)	87.15	-5	(\$471,769)	7,825.2
-6	(\$305,513)	86.70	-6	(\$566,123)	7,834.3
-7	(\$356,432)	86.25	-7	(\$660,477)	7,843.5
-8	(\$407,351)	85.80	-8	(\$754,831)	7,852.6
-9	(\$458,270)	85.35	-9	(\$849,184)	7,861.7
-10	(\$509,189)	84.90	-10	(\$943,538)	7,870.9

Equivalent Availability
Weighting Factor:

0.86%

Heat Rate
Weighting Factor:

2.67%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2022 - December 2022

Hines 2

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)
10	\$194,494	89.84	10	\$751,048	7,436.3
9	\$175,044	89.79	9	\$675,943	7,440.2
8	\$155,595	89.74	8	\$600,839	7,444.0
7	\$136,145	89.68	7	\$525,734	7,447.9
6	\$116,696	89.63	6	\$450,629	7,451.8
5	\$97,247	89.58	5	\$375,524	7,455.6
4	\$77,797	89.53	4	\$300,419	7,459.5
3	\$58,348	89.48	3	\$225,314	7,463.4
2	\$38,899	89.43	2	\$150,210	7,467.2
1	\$19,449	89.38	1	\$75,105	7,471.1
					7,475.0
0	\$0	89.32	0	\$0	7,550.0
					7,625.0
-1	(\$9,690)	89.22	-1	(\$75,105)	7,628.8
-2	(\$19,381)	89.11	-2	(\$150,210)	7,632.7
-3	(\$29,071)	89.00	-3	(\$225,314)	7,636.6
-4	(\$38,762)	88.90	-4	(\$300,419)	7,640.4
-5	(\$48,452)	88.79	-5	(\$375,524)	7,644.3
-6	(\$58,143)	88.68	-6	(\$450,629)	7,648.2
-7	(\$67,833)	88.58	-7	(\$525,734)	7,652.0
-8	(\$77,524)	88.47	-8	(\$600,839)	7,655.9
-9	(\$87,214)	88.36	-9	(\$675,943)	7,659.8
-10	(\$96,905)	88.26	-10	(\$751,048)	7,663.7

Equivalent Availability
Weighting Factor:

0.55%

Heat Rate
Weighting Factor:

2.13%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2022 - December 2022

Hines 3

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)
10	\$168,099	94.82	10	\$1,652,897	7,219.0
9	\$151,289	94.70	9	\$1,487,607	7,229.1
8	\$134,479	94.58	8	\$1,322,317	7,239.1
7	\$117,669	94.46	7	\$1,157,028	7,249.1
6	\$100,859	94.34	6	\$991,738	7,259.2
5	\$84,049	94.22	5	\$826,448	7,269.2
4	\$67,239	94.10	4	\$661,159	7,279.2
3	\$50,430	93.98	3	\$495,869	7,289.3
2	\$33,620	93.86	2	\$330,579	7,299.3
1	\$16,810	93.74	1	\$165,290	7,309.3
					7,319.4
0	\$0	93.62	0	\$0	7,394.4
					7,469.4
-1	(\$40,313)	93.37	-1	(\$165,290)	7,479.4
-2	(\$80,626)	93.13	-2	(\$330,579)	7,489.4
-3	(\$120,939)	92.88	-3	(\$495,869)	7,499.5
-4	(\$161,252)	92.63	-4	(\$661,159)	7,509.5
-5	(\$201,564)	92.38	-5	(\$826,448)	7,519.6
-6	(\$241,877)	92.13	-6	(\$991,738)	7,529.6
-7	(\$282,190)	91.89	-7	(\$1,157,028)	7,539.6
-8	(\$322,503)	91.64	-8	(\$1,322,317)	7,549.7
-9	(\$362,816)	91.39	-9	(\$1,487,607)	7,559.7
-10	(\$403,129)	91.14	-10	(\$1,652,897)	7,569.7

Equivalent Availability
Weighting Factor:

0.48%

Heat Rate
Weighting Factor:

4.68%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2022 - December 2022

Hines 4

Equivalent Availability (Points)	Fuel Savings/Loss (\$)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss (\$)	Average Heat Rate (BTU/KWH)
10	\$201,457	86.44	10	\$1,888,426	6,877.6
9	\$181,311	86.31	9	\$1,699,583	6,888.1
8	\$161,166	86.17	8	\$1,510,741	6,898.6
7	\$141,020	86.04	7	\$1,321,898	6,909.0
6	\$120,874	85.90	6	\$1,133,055	6,919.5
5	\$100,728	85.76	5	\$944,213	6,930.0
4	\$80,583	85.63	4	\$755,370	6,940.4
3	\$60,437	85.49	3	\$566,528	6,950.9
2	\$40,291	85.36	2	\$377,685	6,961.4
1	\$20,146	85.22	1	\$188,843	6,971.8
					6,982.3
0	\$0	85.09	0	\$0	7,057.3
					7,132.3
-1	(\$62,514)	84.80	-1	(\$188,843)	7,142.8
-2	(\$125,027)	84.52	-2	(\$377,685)	7,153.2
-3	(\$187,541)	84.23	-3	(\$566,528)	7,163.7
-4	(\$250,054)	83.95	-4	(\$755,370)	7,174.2
-5	(\$312,568)	83.66	-5	(\$944,213)	7,184.6
-6	(\$375,081)	83.38	-6	(\$1,133,055)	7,195.1
-7	(\$437,595)	83.09	-7	(\$1,321,898)	7,205.5
-8	(\$500,108)	82.81	-8	(\$1,510,741)	7,216.0
-9	(\$562,622)	82.52	-9	(\$1,699,583)	7,226.5
-10	(\$625,135)	82.24	-10	(\$1,888,426)	7,236.9

Equivalent Availability
Weighting Factor:

0.57%

Heat Rate
Weighting Factor:

5.35%

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UNIT PERFORMANCE DATA

Original Sheet No. 7.107.1

EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2022 - December 2022

PLANT/UNIT Bartow 4	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	93.55	81.05	62.10	68.55	73.39	93.55	93.55	93.55	93.55	88.71	48.55	93.55	82.04
2. POF	0.00	12.50	31.45	25.00	20.16	0.00	0.00	0.00	0.00	4.84	45.00	0.00	11.51
3. EUOF	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
4. EUOR	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	698.7	631.1	698.7	676.2	698.7	676.2	698.7	698.7	676.2	698.7	676.2	698.7	8,226.7
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	45.3	40.9	45.3	43.8	45.3	43.8	45.3	45.3	43.8	45.3	43.8	45.3	533.3
9. POH & PPOH	0.0	84.0	234.0	180.0	150.0	0.0	0.0	0.0	0.0	36.0	324.0	0.0	1008.0
10. FOH & PFOH	39.6	35.8	39.6	38.3	39.6	38.3	39.6	39.6	38.3	39.6	38.3	39.6	466.5
11. MOH & PMOH	8.4	7.6	8.4	8.1	8.4	8.1	8.4	8.4	8.1	8.4	8.1	8.4	98.6
12. Oper. Btu(MBtu)	3,870,207	3,886,885	3,160,886	3,671,826	4,373,273	4,495,948	4,756,198	4,663,668	4,440,705	4,209,730	1,853,047	4,277,103	47,887,174
13. Net Gen. (MWH)	495,851.0	504,767.0	396,580.0	469,348.0	569,205.0	590,398.0	626,874.0	612,785.0	582,046.0	545,070.0	224,782.0	554,978.0	6,172,684.0
14. ANOHR (Btu/KWH)	7,805	7,700	7,970	7,823	7,683	7,615	7,587	7,611	7,629	7,723	8,244	7,707	7,758
15. NOF (%)	63.8	71.9	51.0	62.4	73.3	78.5	80.7	78.9	77.4	70.2	29.9	71.4	67.5
16. NSC (MW)	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112
17. ANOHR Equation	ANOHR=	-12.928 x NOF +		8,630.2									

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2022 - December 2022

PLANT/UNIT Crystal River 4	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	17.91	27.98	78.61	79.41	78.35	78.35	78.35	78.62	78.65	78.52	78.55	78.71	69.57
2. POF	77.42	64.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.51
3. EUOF	4.67	7.73	21.39	20.59	21.65	21.65	21.65	21.38	21.35	21.48	21.45	21.29	18.92
4. EUOR	21.65	21.65	21.65	21.65	21.65	21.65	21.65	21.65	21.65	21.65	21.65	21.65	21.65
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	129.5	193.7	593.2	552.5	600.5	581.1	600.5	592.9	572.9	595.6	575.8	590.5	6,178.5
7. RSH	7.6	0.0	9.0	35.4	0.0	0.0	0.0	9.4	10.2	6.0	6.6	12.4	96.6
8. UH	606.9	478.3	141.8	132.1	143.5	138.9	143.5	141.7	136.9	142.4	137.6	141.1	2484.9
9. POH & PPOH	576.0	432.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1008.0
10. FOH & PFOH	31.9	47.8	146.3	136.3	148.1	143.3	148.1	146.2	141.3	146.9	142.0	145.6	1523.9
11. MOH & PMOH	2.8	4.2	12.8	11.9	13.0	12.6	13.0	12.8	12.4	12.9	12.5	12.8	133.6
12. Oper. Btu(MBtu)	844,431	1,113,058	3,668,409	3,224,179	3,766,225	3,637,013	3,890,289	3,964,485	3,658,418	3,807,277	3,264,590	3,544,372	38,447,343
13. Net Gen. (MWH)	91,452.0	113,390.0	386,110.0	330,535.0	399,233.0	385,118.0	419,673.0	435,893.0	391,512.0	407,647.0	330,815.0	367,858.0	4,059,236.0
14. ANOHR (Btu/KWH)	9,234	9,816	9,501	9,754	9,434	9,444	9,270	9,095	9,344	9,340	9,868	9,635	9,472
15. NOF (%)	99.2	82.2	91.4	84.0	93.4	93.1	98.2	103.3	96.0	96.1	80.7	87.5	92.3
16. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
17. ANOHR Equation	ANOHR=	-34.269 x NOF +		12,633.8									

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2022 - December 2022

PLANT/UNIT Crystal River 5	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	87.49	87.46	87.52	87.67	87.48	87.67	87.62	87.43	87.43	79.02	0.00	22.62	74.10
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.68	100.00	74.19	15.34
3. EUOF	12.51	12.54	12.48	12.33	12.52	12.33	12.38	12.57	12.57	11.30	0.00	3.19	10.56
4. EUOR	12.57	12.57	12.57	12.57	12.57	12.57	12.57	12.57	12.57	12.57	0.00	12.57	12.57
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	662.7	599.9	660.9	632.3	663.1	631.9	655.9	665.7	644.3	598.8	0.0	168.8	6,584.2
7. RSH	3.4	1.6	5.4	13.4	3.0	13.8	11.0	0.0	0.0	2.8	0.0	3.4	57.8
8. UH	77.9	70.5	77.7	74.3	77.9	74.3	77.1	78.3	75.7	142.4	720.0	571.8	2118.0
9. POH & PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.0	720.0	552.0	1344.0
10. FOH & PFOH	83.5	75.6	83.3	79.7	83.6	79.6	82.7	83.9	81.2	75.5	0.0	21.3	829.8
11. MOH & PMOH	9.6	8.7	9.5	9.1	9.6	9.1	9.5	9.6	9.3	8.6	0.0	2.4	95.0
12. Oper. Btu(MBtu)	4,205,963	3,679,129	3,748,326	2,869,817	3,330,227	3,287,084	3,536,908	3,465,338	3,611,838	3,200,470	-	962,965	36,052,993
13. Net Gen. (MWH)	458,989.0	394,233.0	387,666.0	276,458.0	329,960.0	329,349.0	358,812.0	347,286.0	371,819.0	323,655.0	-	99,842.0	3,678,069.0
14. ANOHR (Btu/KWH)	9,164	9,332	9,669	10,381	10,093	9,981	9,857	9,978	9,714	9,889	-	9,645	9,802
15. NOF (%)	99.2	94.2	84.0	62.6	71.3	74.7	78.4	74.7	82.7	77.4	0.0	84.8	80.0
16. NSC (MW)	698	698	698	698	698	698	698	698	698	698	698	698	698
17. ANOHR Equation	ANOHR=	-33.268 x NOF +		12,464.7									

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2022 - December 2022

PLANT/UNIT Hines 1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.73	97.02	97.04	48.60	75.58	93.70	93.15	92.85	93.07	94.56	93.07	97.29	89.40
2. POF	0.00	0.00	0.00	50.00	19.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.75
3. EUOF	3.27	2.98	2.96	1.40	5.07	6.30	6.85	7.15	6.93	5.44	6.93	2.71	4.84
4. EUOR	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	311.9	256.7	282.5	128.9	482.8	581.1	652.8	681.2	639.1	518.6	639.5	258.3	5,433.5
7. RSH	408.6	396.0	440.2	221.4	80.8	95.1	42.0	11.5	32.8	186.4	32.4	466.2	2413.4
8. UH	23.5	19.3	21.3	369.7	180.4	43.8	49.2	51.3	48.1	39.0	48.1	19.5	913.1
9. POH & PPOH	0.0	0.0	0.0	360.0	144.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	504.0
10. FOH & PFOH	11.8	9.7	10.7	4.9	18.2	22.0	24.7	25.7	24.1	19.6	24.2	9.8	205.2
11. MOH & PMOH	12.6	10.3	11.4	5.2	19.5	23.4	26.3	27.4	25.7	20.9	25.8	10.4	218.9
12. Oper. Btu(MBtu)	687,275	604,719	688,155	217,055	1,305,970	1,490,942	1,718,992	1,753,481	1,572,546	1,284,405	1,808,452	688,818	13,840,296
13. Net Gen. (MWH)	86,980.0	77,374.0	88,569.0	26,537.0	171,610.0	193,788.0	224,605.0	228,062.0	202,772.0	165,820.0	240,035.0	90,237.0	1,796,389.0
14. ANOHR (Btu/KWH)	7,902	7,816	7,770	8,179	7,610	7,694	7,653	7,689	7,755	7,746	7,534	7,633	7,705
15. NOF (%)	56.9	61.5	64.0	42.0	72.5	68.1	70.2	68.3	64.8	65.3	76.6	71.3	67.5
16. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
17. ANOHR Equation	ANOHR=	-18.653 x NOF +		8,963.0									

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2022 - December 2022

PLANT/UNIT Hines 2	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	99.33	99.58	57.57	26.39	98.44	98.42	98.35	98.35	98.36	98.64	98.57	99.75	89.32
2. POF	0.00	0.00	41.94	73.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.59
3. EUOF	0.67	0.42	0.50	0.28	1.56	1.58	1.65	1.65	1.64	1.36	1.43	0.25	1.09
4. EUOR	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	284.1	161.4	210.7	115.0	661.3	646.1	697.2	700.8	672.6	576.7	587.3	105.9	5,419.1
7. RSH	456.0	508.4	218.4	75.4	73.6	65.0	37.2	33.6	38.2	159.4	124.6	636.6	2426.4
8. UH	3.9	2.2	314.9	529.6	9.1	8.9	9.6	9.6	9.2	7.9	8.1	1.5	914.5
9. POH & PPOH	0.0	0.0	312.0	528.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	840.0
10. FOH & PFOH	2.5	1.4	1.9	1.0	5.8	5.7	6.1	6.2	5.9	5.1	5.2	0.9	47.7
11. MOH & PMOH	2.5	1.4	1.8	1.0	5.8	5.7	6.1	6.1	5.9	5.0	5.1	0.9	47.5
12. Oper. Btu(MBtu)	711,786	411,036	531,083	279,369	1,932,799	1,905,447	2,085,815	2,045,422	1,917,032	1,669,201	1,806,242	298,836	15,599,315
13. Net Gen. (MWH)	93,132.0	53,853.0	69,522.0	36,464.0	256,379.0	252,975.0	277,319.0	271,283.0	253,674.0	221,205.0	240,832.0	39,505.0	2,066,143.0
14. ANOHR (Btu/KWH)	7,643	7,633	7,639	7,662	7,539	7,532	7,521	7,540	7,557	7,546	7,500	7,565	7,550
15. NOF (%)	61.6	62.7	62.0	59.6	72.9	73.6	74.8	72.8	70.9	72.1	77.1	70.1	71.7
16. NSC (MW)	532	532	532	532	532	532	532	532	532	532	532	532	532
17. ANOHR Equation	ANOHR=	-9.236 x NOF +		8,211.9									

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2022 - December 2022

PLANT/UNIT Hines 3	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	97.58	97.54	97.48	97.42	97.17	97.17	97.17	97.16	97.16	97.21	58.30	91.69	93.62
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.00	6.45	3.84
3. EUOF	2.42	2.46	2.52	2.58	2.83	2.83	2.83	2.84	2.84	2.79	1.70	1.85	2.54
4. EUOR	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	616.0	565.8	642.4	636.6	721.0	696.7	720.7	722.3	700.0	709.8	420.0	472.4	7,623.6
7. RSH	110.4	90.0	83.2	65.2	2.4	3.4	2.7	1.0	0.0	13.9	0.0	210.1	582.3
8. UH	17.6	16.2	18.4	18.2	20.6	19.9	20.6	20.7	20.0	20.3	300.0	61.5	554.1
9. POH & PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	288.0	48.0	336.0
10. FOH & PFOH	12.1	11.1	12.6	12.5	14.1	13.6	14.1	14.1	13.7	13.9	8.2	9.3	149.3
11. MOH & PMOH	5.9	5.5	6.2	6.1	6.9	6.7	6.9	7.0	6.7	6.8	4.0	4.6	73.4
12. Oper. Btu(MBtu)	1,569,397	1,467,080	1,669,236	1,561,064	2,023,249	1,983,718	2,077,287	2,047,058	1,911,486	1,968,048	1,346,654	1,164,497	20,804,631
13. Net Gen. (MWH)	210,253.0	197,001.0	224,210.0	208,124.0	274,746.0	269,974.0	283,243.0	278,392.0	258,530.0	266,772.0	186,975.0	155,354.0	2,813,574.0
14. ANOHR (Btu/KWH)	7,464	7,447	7,445	7,501	7,364	7,348	7,334	7,353	7,394	7,377	7,202	7,496	7,394
15. NOF (%)	65.3	66.6	66.7	62.5	72.9	74.1	75.1	73.7	70.6	71.9	85.1	62.9	70.6
16. NSC (MW)	523	523	523	523	523	523	523	523	523	523	523	523	523
17. ANOHR Equation	ANOHR=	-13.193 x NOF +		8,325.4									

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2022 - December 2022

PLANT/UNIT Hines 4	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.94	96.73	96.76	96.79	96.70	96.70	96.70	96.70	96.70	0.00	54.80	96.80	85.09
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	43.33	0.00	12.05
3. EUOF	3.06	3.27	3.24	3.21	3.30	3.30	3.30	3.30	3.30	0.00	1.87	3.20	2.86
4. EUOR	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	0.00	3.30	3.30	3.30
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	667.7	643.3	707.8	677.2	720.0	696.7	720.0	720.0	696.7	0.0	394.8	697.5	7,341.8
7. RSH	54.0	7.2	12.6	20.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.2	117.2
8. UH	22.3	21.5	23.6	22.6	24.0	23.3	24.0	24.0	23.3	744.0	325.2	23.3	1301.0
9. POH & PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	744.0	312.0	0.0	1056.0
10. FOH & PFOH	22.2	21.4	23.5	22.5	23.9	23.2	23.9	23.9	23.2	0.0	13.1	23.2	244.0
11. MOH & PMOH	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0	0.3	0.6	6.4
12. Oper. Btu(MBtu)	1,817,835	1,831,225	2,033,981	1,731,307	2,251,615	2,232,302	2,308,052	2,154,740	2,106,619	-	1,256,586	2,046,267	21,778,604
13. Net Gen. (MWH)	255,970.0	258,676.0	287,519.0	242,764.0	320,395.0	318,290.0	329,107.0	305,531.0	298,947.0	-	179,068.0	289,704.0	3,085,971.0
14. ANOHR (Btu/KWH)	7,102	7,079	7,074	7,132	7,028	7,013	7,013	7,052	7,047	-	7,017	7,063	7,057
15. NOF (%)	74.3	77.9	78.7	69.5	86.2	88.5	88.6	82.2	83.2	0.0	87.9	80.5	81.5
16. NSC (MW)	516	516	516	516	516	516	516	516	516	516	516	516	516
17. ANOHR Equation	ANOHR=	-6.203 x NOF +		7,562.6									

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PLANNED OUTAGE SCHEDULES

Duke Energy Florida
Period of: January 2022 - December 2022

<u>Plant/Unit</u>	<u>Planned Outage Dates</u>	<u>Reason for Outage</u>
Bartow 4	02/12 (0001) - 02/25 (2400)	3 x 1, Borescopes B, Gen Minor B, BOP B
Bartow 4	03/01 (0001) - 03/13 (2400)	2 x 1, Gulfstream pipeline outage, B & D avail on fuel oil, A & C not available
Bartow 4	03/19 (0001) - 05/25 (2400)	3 x 1, Borescope D, BOP D
Bartow 4	10/29 (0001) - 11/27 (2400)	3 x 0, Replace P91 delam valves, L-0 inspection plus boroscopes (A & C), BOP, CW pipe liner replacement
Crystal River 4	01/08 (0001) - 02/18 (2400)	BOP, SCR replacement, cooling tower work
Crystal River 5	10/29 (0001) - 12/23 (2400)	Steam turbine work
Hines 1	04/16 (0001) - 05/06 (2400)	Full Block, BOP, Borescopes, A&B Gen Minor, T3000 upgrade
Hines 2	03/19 (0001) - 04/22 (2400)	Full Block, BOP, Borescopes, (A&B) Exciter major, (A&B) Gen Major, LP/IP minor inspection, L-0 inspection
Hines 3	11/19 (0001) - 12/02 (2400)	Full Block, BOP, Borescopes, L-0 inspections
Hines 4	10/01 (0001) - 11/13 (2400)	Full Block, CT- MI (B), Gen-Major (B), BOP, Borescope

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AVERAGE NET OPERATING HEAT RATE CURVES

DUKE ENERGY FLORIDA

Bartow Unit 4

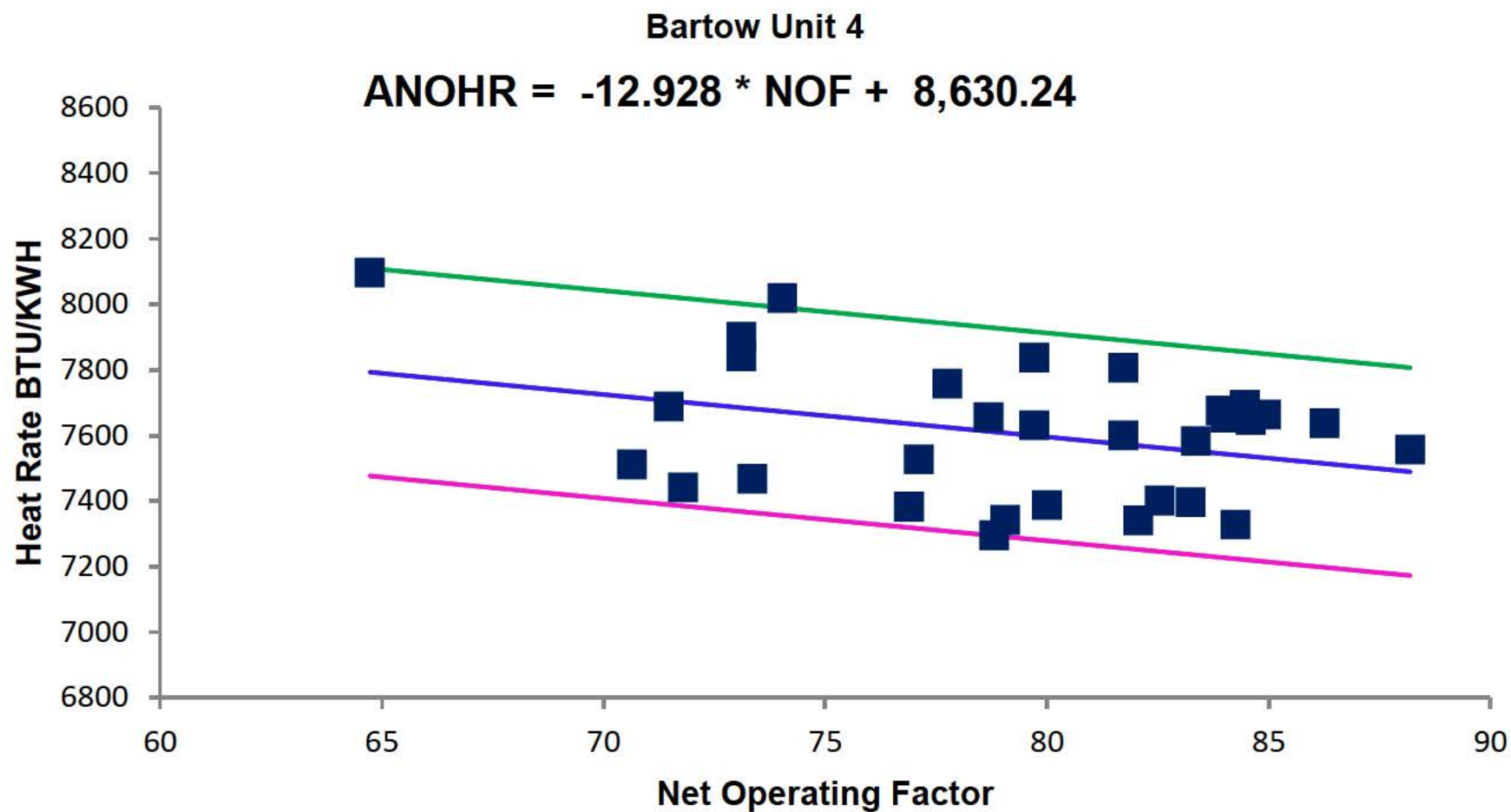
ANOHR = -12.928 * NOF + 8,630.24

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-18	84.5	7,694	7,538	155.3	316.9
Aug-18	83.9	7,677	7,545	131.8	316.9
Sep-18	86.3	7,638	7,515	123.0	316.9
Oct-18	88.2	7,558	7,490	67.8	316.9
Nov-18	84.6	7,647	7,537	110.2	316.9
Dec-18	78.7	7,657	7,613	44.4	316.9
Jan-19	79.7	7,632	7,600	32.5	316.9
Feb-19	71.5	7,689	7,706	-17.1	316.9
Apr-19	73.1	7,902	7,685	217.4	316.9
May-19	83.4	7,583	7,553	30.5	316.9
Jun-19	84.0	7,655	7,544	111.1	316.9
Jul-19	81.7	7,808	7,574	234.4	316.9
Aug-19	85.0	7,665	7,532	132.6	316.9
Sep-19	73.1	7,842	7,685	156.7	316.9
Dec-19	81.7	7,600	7,574	26.7	316.9
Jan-20	78.8	7,296	7,611	-315.1	316.9
Feb-20	77.8	7,759	7,625	133.8	316.9
Mar-20	79.7	7,838	7,600	238.7	316.9
Apr-20	70.6	7,513	7,717	-204.1	316.9
May-20	77.1	7,529	7,633	-104.8	316.9
Jun-20	82.6	7,402	7,563	-160.7	316.9
Jul-20	84.3	7,329	7,541	-211.8	316.9
Aug-20	82.1	7,342	7,569	-227.5	316.9
Sep-20	80.0	7,388	7,596	-207.7	316.9
Oct-20	83.3	7,397	7,554	-157.3	316.9
Jan-21	64.7	8,098	7,793	304.1	316.9
Feb-21	74.0	8,020	7,673	346.5	316.9
Mar-21	76.9	7,384	7,636	-252.4	316.9
Apr-21	79.1	7,342	7,608	-265.8	316.9
May-21	73.4	7,468	7,682	-213.6	316.9
Jun-21	71.8	7,443	7,702	-259.5	316.9

Regression Output:

Constant	8630.24
Std Err of Y Est	195.821988
R Squared	0.119607861
No. of Observations	31
Degrees of Freedom	29
X Coefficient	-12.92805851
Std Err of Coef.	6.513171687



DUKE ENERGY FLORIDA

Crystal River Unit 4

ANOHR = -34.269 * NOF + 12,633.75

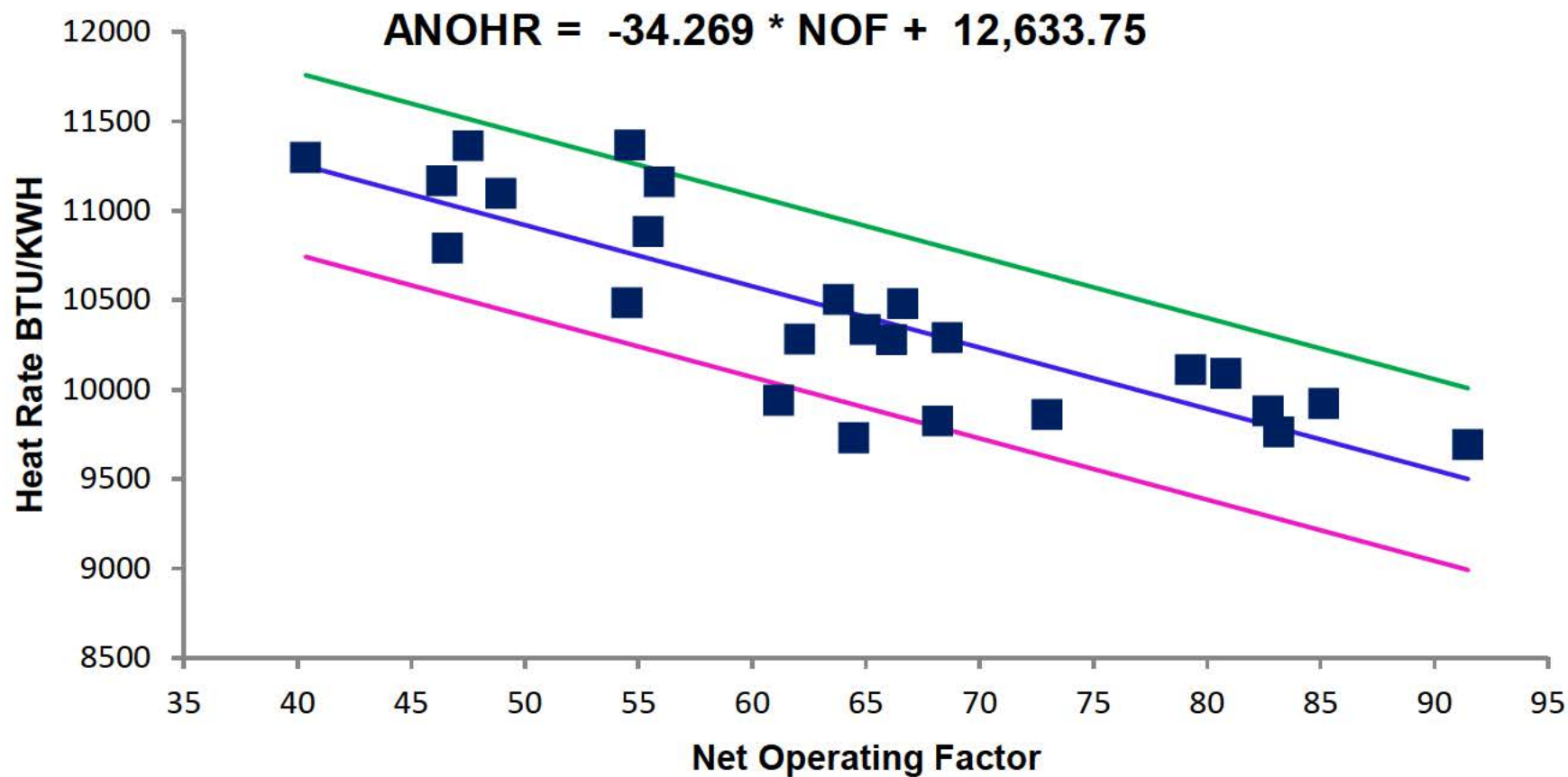
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-18	82.7	9,880	9,800	79.7	508.3
Aug-18	85.1	9,922	9,717	204.8	508.3
Sep-18	79.3	10,111	9,917	194.9	508.3
Oct-18	83.2	9,762	9,784	-21.8	508.3
Nov-18	80.8	10,090	9,863	226.8	508.3
Dec-18	91.5	9,691	9,499	192.5	508.3
Jan-19	46.4	11,168	11,045	122.2	508.3
Mar-19	61.2	9,939	10,537	-598.1	508.3
Apr-19	62.1	10,283	10,506	-222.3	508.3
May-19	65.0	10,337	10,407	-70.3	508.3
Jun-19	63.8	10,505	10,448	57.2	508.3
Jul-19	54.5	10,485	10,766	-280.5	508.3
Aug-19	55.9	11,162	10,717	444.8	508.3
Sep-19	46.6	10,791	11,036	-245.7	508.3
Oct-19	68.2	9,825	10,298	-472.9	508.3
Nov-19	73.0	9,861	10,133	-272.9	508.3
May-20	40.4	11,299	11,251	48.1	508.3
Jun-20	49.0	11,098	10,956	142.4	508.3
Jul-20	55.4	10,885	10,734	150.9	508.3
Aug-20	54.6	11,368	10,762	606.3	508.3
Sep-20	47.5	11,364	11,006	357.7	508.3
Oct-20	64.5	9,730	10,425	-694.2	508.3
Apr-21	66.1	10,281	10,368	-86.9	508.3
May-21	68.6	10,293	10,284	8.5	508.3
Jun-21	66.6	10,479	10,351	128.7	508.3

Regression Output:

Constant	12633.75
Std Err of Y Est	315.3665061
R Squared	0.700704742
No. of Observations	25
Degrees of Freedom	23
X Coefficient	-34.26943431
Std Err of Coef.	4.670091692

Crystal River Unit 4



DUKE ENERGY FLORIDA

Crystal River Unit 5

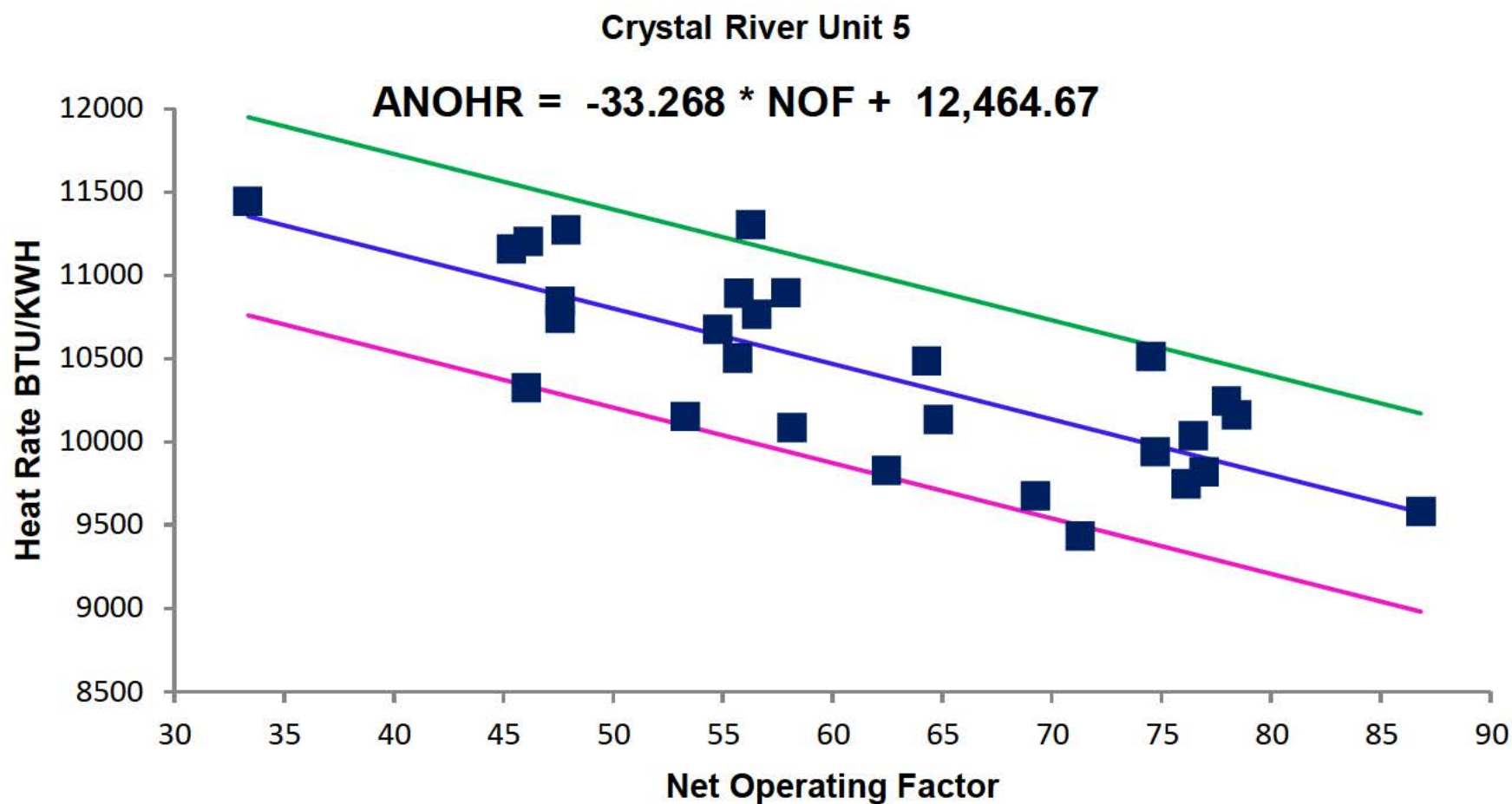
ANOHR = -33.268 * NOF + 12,464.67

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-18	78.0	10,246	9,870	376.0	594.6
Aug-18	77.0	9,820	9,905	-84.2	594.6
Sep-18	76.5	10,040	9,921	119.8	594.6
Oct-18	74.7	9,944	9,979	-35.1	594.6
Nov-18	78.4	10,164	9,855	308.3	594.6
Dec-18	76.2	9,749	9,931	-182.0	594.6
Jan-19	47.6	10,845	10,882	-36.7	594.6
Jun-19	46.1	11,203	10,930	273.8	594.6
Jul-19	53.3	10,155	10,692	-536.6	594.6
Aug-19	54.8	10,677	10,643	34.2	594.6
Sep-19	58.2	10,086	10,530	-444.3	594.6
Oct-19	69.3	9,675	10,161	-485.4	594.6
Nov-19	71.3	9,435	10,093	-657.8	594.6
Mar-20	33.4	11,447	11,355	92.1	594.6
Apr-20	46.1	10,327	10,933	-606.0	594.6
May-20	47.6	10,742	10,882	-140.3	594.6
Jun-20	45.4	11,158	10,956	202.8	594.6
Jul-20	55.7	10,893	10,610	283.1	594.6
Aug-20	56.3	11,305	10,593	712.1	594.6
Sep-20	47.9	11,273	10,872	400.5	594.6
Oct-20	62.5	9,832	10,386	-554.0	594.6
Dec-20	56.6	10,767	10,583	184.2	594.6
Jan-21	55.7	10,505	10,612	-107.2	594.6
Feb-21	86.8	9,582	9,575	6.8	594.6
Mar-21	64.8	10,137	10,308	-171.4	594.6
Apr-21	57.9	10,896	10,539	357.4	594.6
May-21	64.3	10,486	10,326	160.8	594.6
Jun-21	74.5	10,514	9,985	528.7	594.6

Regression Output:

Constant	12464.67
Std Err of Y Est	368.0666402
R Squared	0.599002417
No. of Observations	28
Degrees of Freedom	26
X Coefficient	-33.26822889
Std Err of Coef.	5.338258461



DUKE ENERGY FLORIDA

Hines Unit 1

ANOHR = -18.653 * NOF + 8,963.04

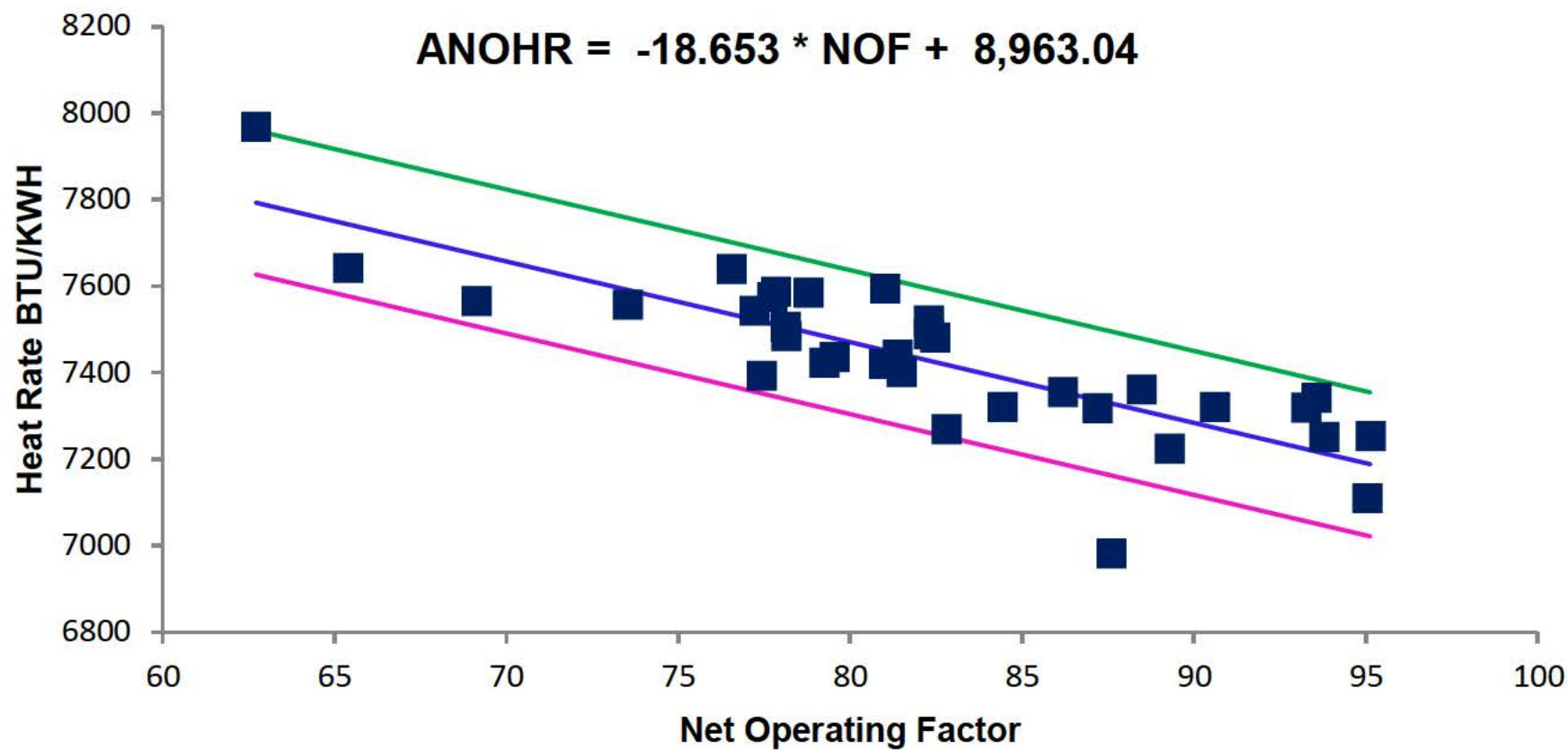
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-18	93.6	7,343	7,218	124.7	166.4
Aug-18	90.6	7,321	7,273	47.8	166.4
Sep-18	93.3	7,319	7,223	96.1	166.4
Oct-18	87.2	7,318	7,337	-18.6	166.4
Nov-18	82.8	7,270	7,419	-148.7	166.4
Dec-18	62.7	7,969	7,793	175.2	166.4
Jan-19	65.4	7,642	7,743	-100.9	166.4
Feb-19	81.5	7,401	7,443	-41.4	166.4
Mar-19	79.6	7,437	7,479	-42.5	166.4
Apr-19	69.1	7,566	7,674	-107.9	166.4
May-19	82.3	7,489	7,428	60.6	166.4
Jun-19	81.0	7,420	7,452	-31.9	166.4
Jul-19	82.3	7,520	7,428	92.3	166.4
Aug-19	86.2	7,355	7,355	-0.6	166.4
Sep-19	81.4	7,442	7,445	-2.8	166.4
Oct-19	88.5	7,361	7,313	48.4	166.4
Nov-19	95.1	7,254	7,188	65.4	166.4
Dec-19	84.4	7,321	7,388	-67.3	166.4
Jan-20	81.0	7,594	7,452	142.3	166.4
Feb-20	76.6	7,640	7,535	104.9	166.4
Mar-20	78.1	7,506	7,506	0.1	166.4
Apr-20	78.1	7,485	7,506	-20.6	166.4
May-20	77.7	7,576	7,513	63.0	166.4
Jun-20	78.8	7,585	7,494	91.1	166.4
Jul-20	82.5	7,482	7,425	57.3	166.4
Aug-20	79.3	7,423	7,485	-62.0	166.4
Sep-20	77.8	7,587	7,511	76.1	166.4
Nov-20	77.4	7,394	7,519	-124.8	166.4
Dec-20	95.1	7,111	7,190	-79.5	166.4
Jan-21	93.8	7,251	7,214	37.8	166.4
Feb-21	77.2	7,543	7,523	20.3	166.4
Mar-21	89.3	7,225	7,298	-73.1	166.4
Apr-21	87.6	6,982	7,329	-346.7	166.4
Jun-21	73.5	7,557	7,592	-34.2	166.4

Regression Output:

Constant	8963.04
Std Err of Y Est	102.6621215
R Squared	0.678433624
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-18.65262037
Std Err of Coef.	2.27010788

Hines Unit 1



DUKE ENERGY FLORIDA

Hines Unit 2

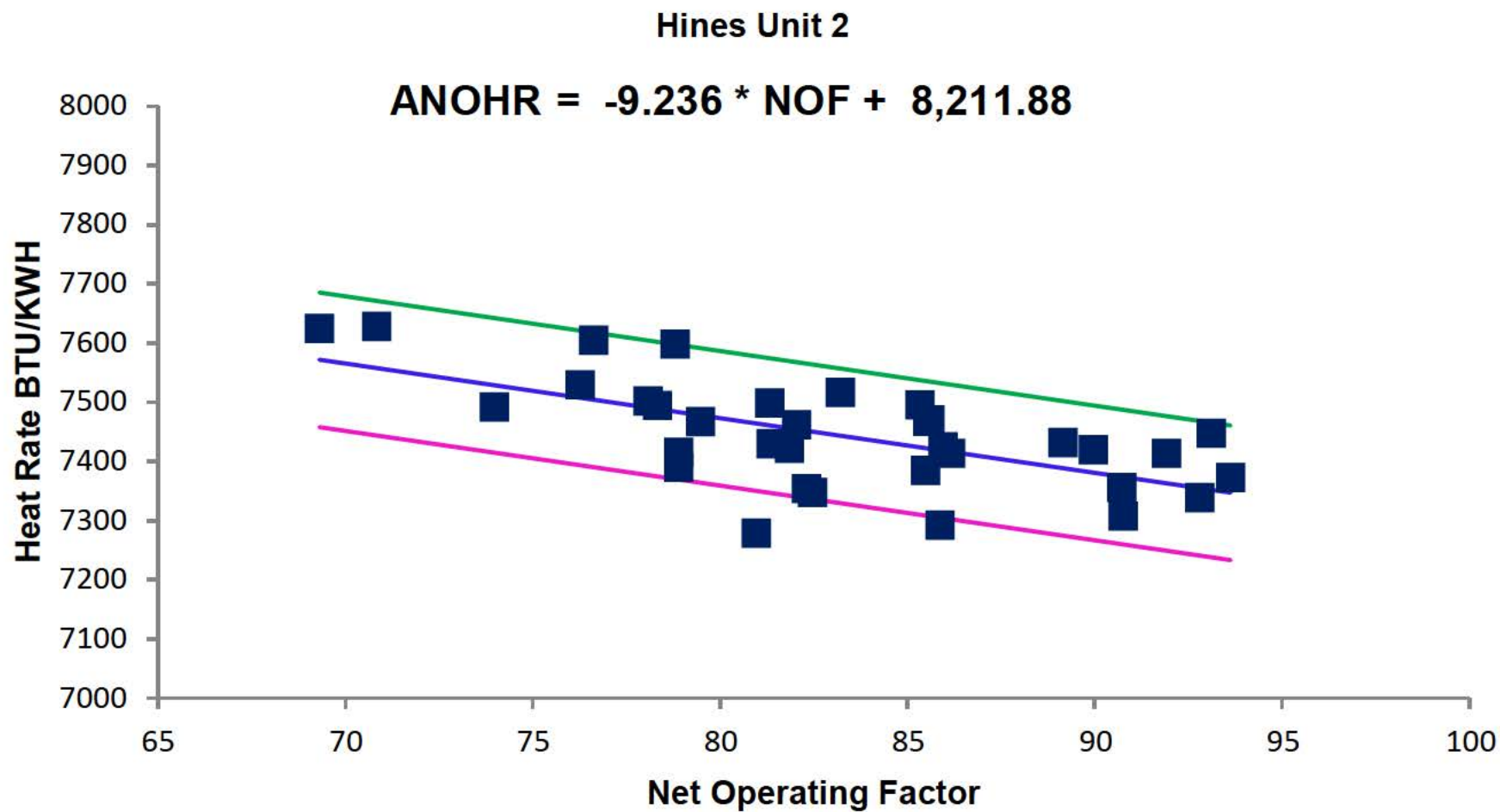
ANOHR = -9.236 * NOF + 8,211.88

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-18	93.1	7,447	7,352	95.6	113.7
Aug-18	92.8	7,339	7,355	-15.9	113.7
Sep-18	91.9	7,414	7,363	50.9	113.7
Oct-18	90.8	7,307	7,374	-66.4	113.7
Nov-18	78.9	7,415	7,483	-68.1	113.7
Dec-18	76.3	7,529	7,508	21.9	113.7
Jan-19	81.0	7,279	7,464	-185.3	113.7
Feb-19	82.3	7,354	7,452	-97.6	113.7
Apr-19	90.7	7,356	7,374	-18.2	113.7
May-19	89.2	7,432	7,389	43.0	113.7
Jun-19	86.0	7,425	7,418	6.6	113.7
Jul-19	85.6	7,468	7,422	46.6	113.7
Aug-19	85.6	7,470	7,421	49.0	113.7
Sep-19	81.3	7,498	7,461	37.7	113.7
Oct-19	90.0	7,419	7,381	38.4	113.7
Nov-19	93.6	7,373	7,347	25.6	113.7
Dec-19	81.9	7,422	7,456	-33.6	113.7
Jan-20	78.9	7,390	7,483	-93.3	113.7
Feb-20	86.2	7,414	7,416	-2.2	113.7
Apr-20	69.3	7,625	7,572	53.1	113.7
May-20	70.8	7,628	7,558	70.4	113.7
Jun-20	78.8	7,599	7,484	114.5	113.7
Jul-20	83.2	7,516	7,443	72.9	113.7
Aug-20	81.4	7,430	7,460	-30.8	113.7
Sep-20	79.5	7,467	7,478	-10.8	113.7
Oct-20	85.5	7,385	7,422	-37.4	113.7
Nov-20	78.1	7,503	7,491	11.8	113.7
Dec-20	82.0	7,462	7,454	7.9	113.7
Jan-21	74.0	7,492	7,529	-36.5	113.7
Feb-21	76.6	7,605	7,504	100.7	113.7
Mar-21	78.3	7,495	7,488	6.5	113.7
Apr-21	85.9	7,293	7,419	-126.1	113.7
May-21	82.5	7,348	7,450	-102.6	113.7
Jun-21	85.3	7,495	7,424	71.5	113.7

Regression Output:

Constant	8211.88
Std Err of Y Est	70.149383
R Squared	0.408343482
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-9.235879109
Std Err of Coef.	1.965283752



DUKE ENERGY FLORIDA

Hines Unit 3

ANOHR = -13.193 * NOF + 8,325.38

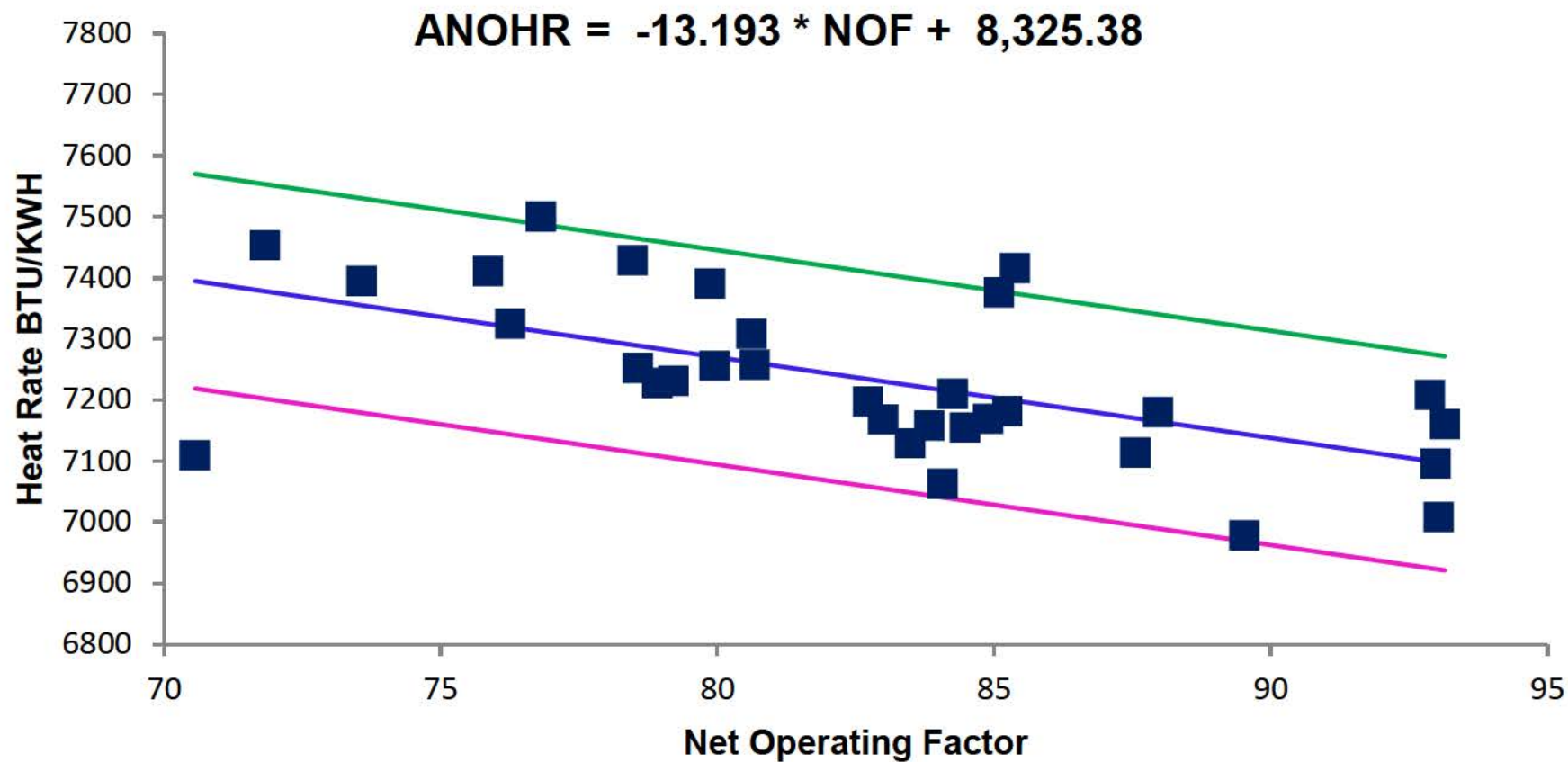
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-18	93.0	7,009	7,098	-89.2	175.4
Aug-18	92.9	7,209	7,100	108.9	175.4
Sep-18	93.2	7,161	7,096	64.1	175.4
Nov-18	85.2	7,182	7,201	-19.0	175.4
Dec-18	85.1	7,376	7,203	173.1	175.4
Jan-19	85.4	7,416	7,199	217.3	175.4
Feb-19	76.3	7,325	7,319	6.0	175.4
Mar-19	83.0	7,169	7,230	-61.9	175.4
Apr-19	84.1	7,063	7,216	-153.3	175.4
May-19	88.0	7,180	7,165	15.2	175.4
Jun-19	84.3	7,211	7,214	-3.3	175.4
Jul-19	84.5	7,155	7,211	-55.9	175.4
Aug-19	84.9	7,170	7,205	-35.8	175.4
Sep-19	80.6	7,309	7,262	46.8	175.4
Oct-19	93.0	7,096	7,099	-2.4	175.4
Nov-19	89.5	6,979	7,144	-165.3	175.4
Dec-19	75.9	7,411	7,325	86.0	175.4
Jan-20	76.8	7,500	7,312	187.9	175.4
Feb-20	82.7	7,197	7,234	-36.6	175.4
Mar-20	80.0	7,256	7,271	-14.4	175.4
Apr-20	78.9	7,228	7,284	-56.4	175.4
May-20	73.6	7,395	7,355	39.8	175.4
Jun-20	83.5	7,129	7,224	-94.7	175.4
Jul-20	80.7	7,258	7,261	-3.3	175.4
Aug-20	78.5	7,429	7,290	139.0	175.4
Sep-20	79.2	7,232	7,280	-48.5	175.4
Oct-20	87.6	7,114	7,170	-56.4	175.4
Nov-20	78.6	7,253	7,289	-36.0	175.4
Dec-20	83.8	7,159	7,219	-60.9	175.4
Jan-21	70.6	7,110	7,395	-285.0	175.4
Feb-21	71.8	7,453	7,378	75.6	175.4
Jun-21	79.9	7,390	7,272	118.6	175.4

Regression Output:

Constant	8325.38
Std Err of Y Est	108.3033838
R Squared	0.355331936
No. of Observations	32
Degrees of Freedom	30
X Coefficient	-13.19319703
Std Err of Coef.	3.244444713

Hines Unit 3



DUKE ENERGY FLORIDA

Hines Unit 4

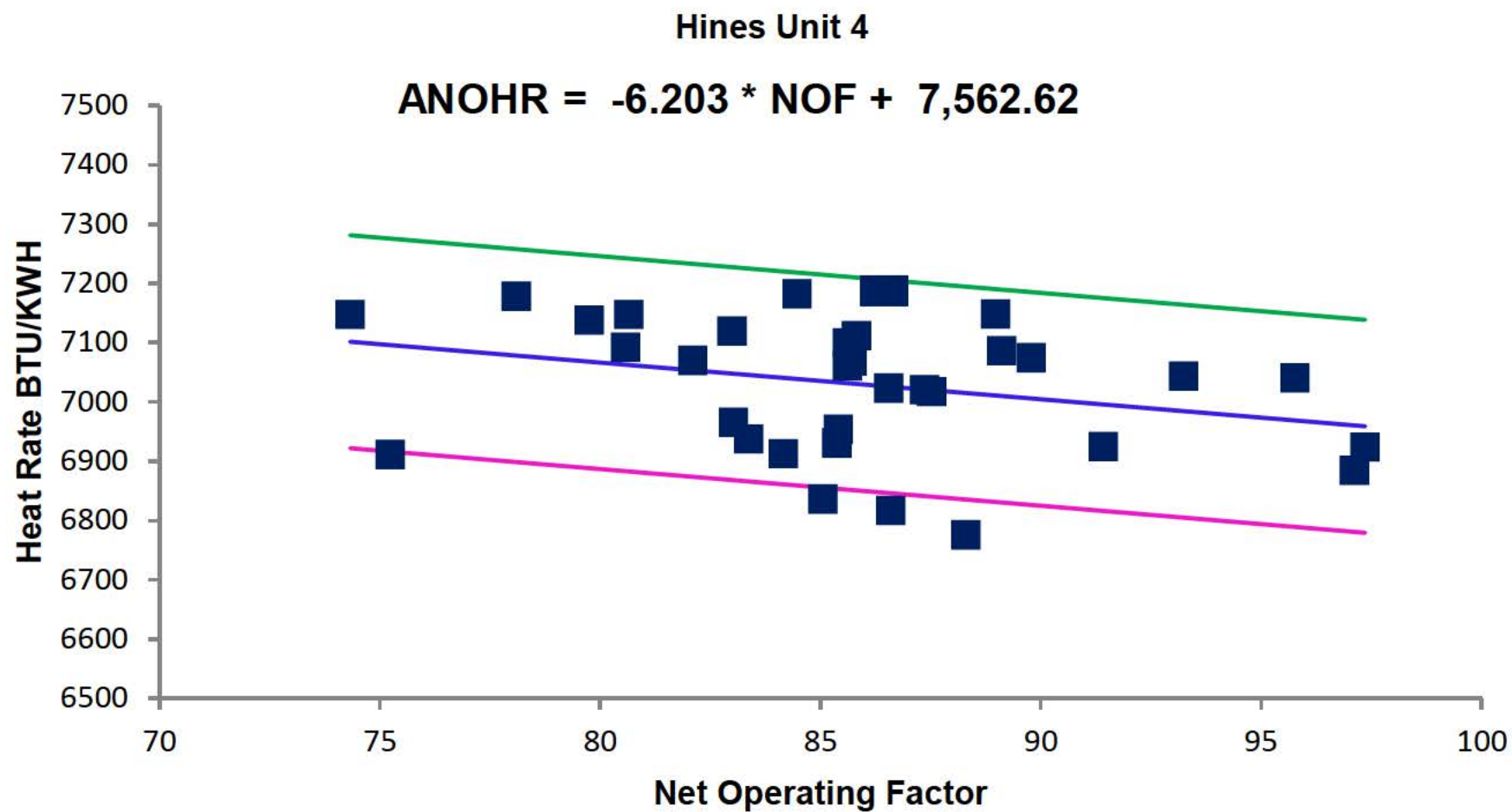
ANOHR = -6.203 * NOF + 7,562.62

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-18	95.8	7,040	6,969	71.6	179.6
Aug-18	93.2	7,044	6,984	59.9	179.6
Sep-18	97.4	6,924	6,959	-34.8	179.6
Oct-18	97.1	6,885	6,960	-75.5	179.6
Dec-18	85.1	6,836	7,035	-199.1	179.6
Jan-19	91.4	6,925	6,996	-70.5	179.6
Feb-19	84.2	6,913	7,041	-127.4	179.6
Mar-19	83.4	6,937	7,045	-108.3	179.6
Apr-19	86.6	6,817	7,025	-208.5	179.6
May-19	89.8	7,075	7,006	69.0	179.6
Jun-19	85.6	7,061	7,032	29.1	179.6
Jul-19	86.2	7,188	7,028	160.2	179.6
Aug-19	86.6	7,187	7,025	162.3	179.6
Sep-19	85.7	7,069	7,031	38.3	179.6
Oct-19	85.6	7,100	7,032	68.0	179.6
Dec-19	88.3	6,776	7,015	-239.4	179.6
Jan-20	85.4	6,930	7,033	-102.8	179.6
Feb-20	83.0	6,965	7,048	-82.1	179.6
Mar-20	78.1	7,178	7,078	99.8	179.6
Apr-20	79.8	7,138	7,068	70.5	179.6
May-20	82.1	7,070	7,053	17.2	179.6
Jun-20	85.8	7,112	7,030	81.5	179.6
Jul-20	83.0	7,119	7,048	71.7	179.6
Aug-20	80.6	7,092	7,063	29.2	179.6
Sep-20	80.7	7,147	7,062	85.0	179.6
Oct-20	89.1	7,087	7,010	76.7	179.6
Nov-20	84.5	7,182	7,039	143.5	179.6
Dec-20	74.3	7,148	7,102	46.1	179.6
Jan-21	75.2	6,911	7,096	-184.9	179.6
Feb-21	87.4	7,021	7,021	0.1	179.6
Mar-21	87.5	7,018	7,020	-2.0	179.6
Apr-21	85.4	6,953	7,033	-79.5	179.6
May-21	86.6	7,023	7,026	-2.7	179.6
Jun-21	89.0	7,149	7,011	138.0	179.6

Regression Output:

Constant	7562.62
Std Err of Y Est	110.8520331
R Squared	0.083574591
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-6.203438538
Std Err of Coef.	3.631356817



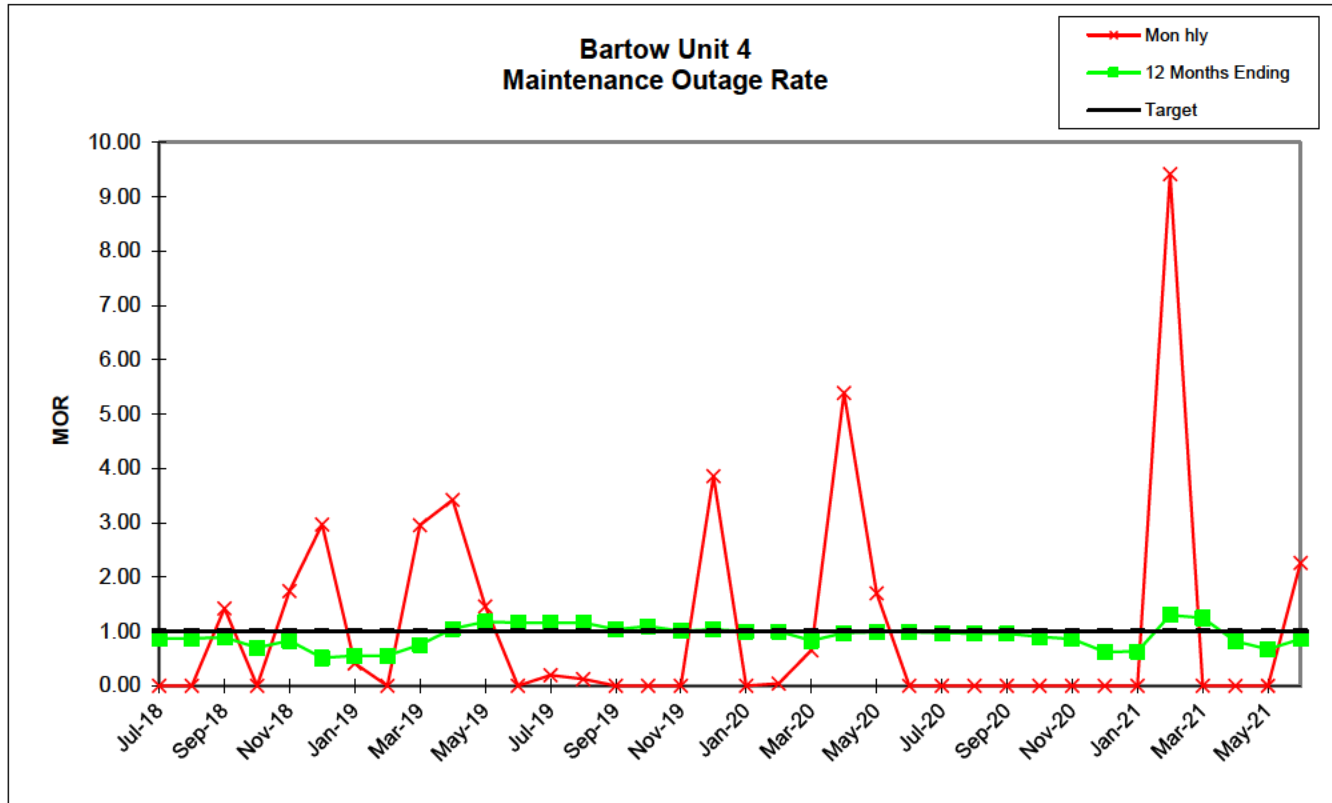
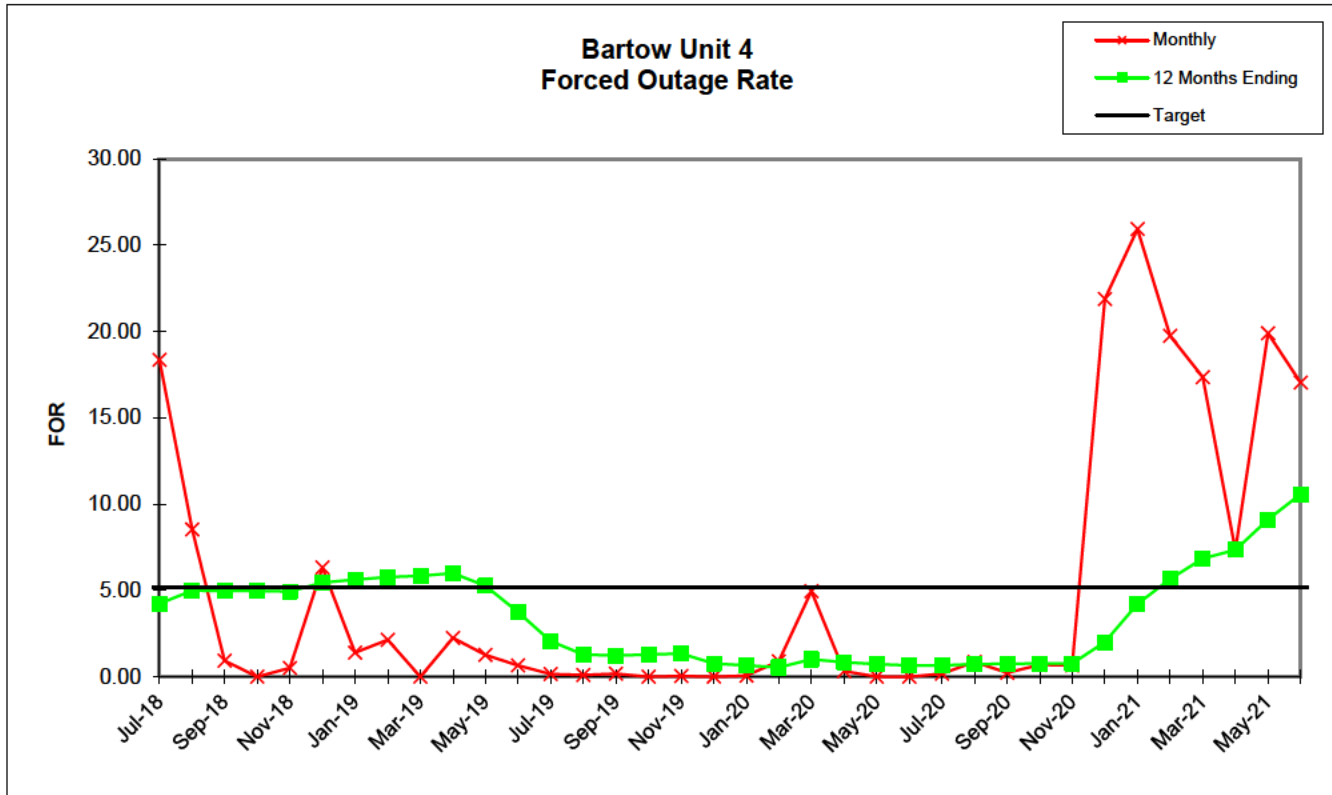
UNPLANNED OUTAGE RATE TABLES AND GRAPHS

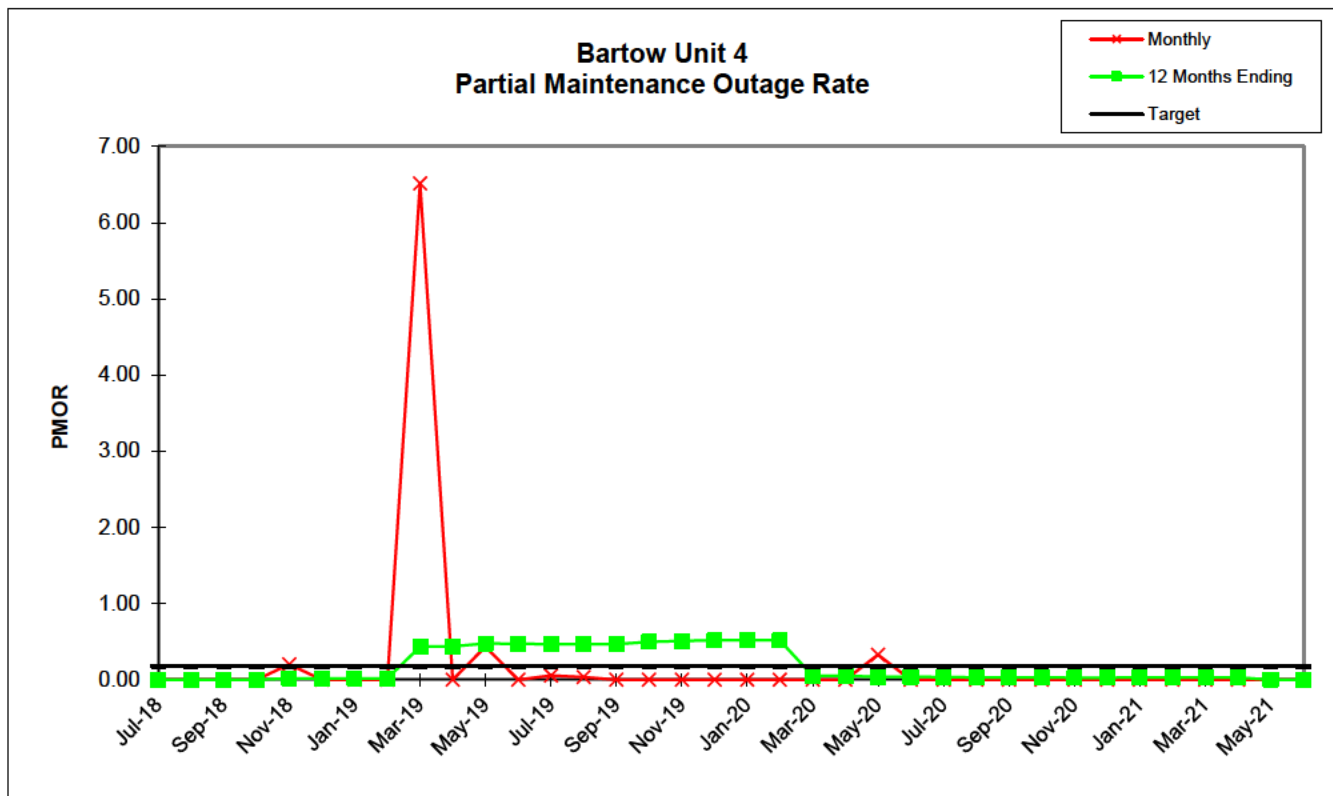
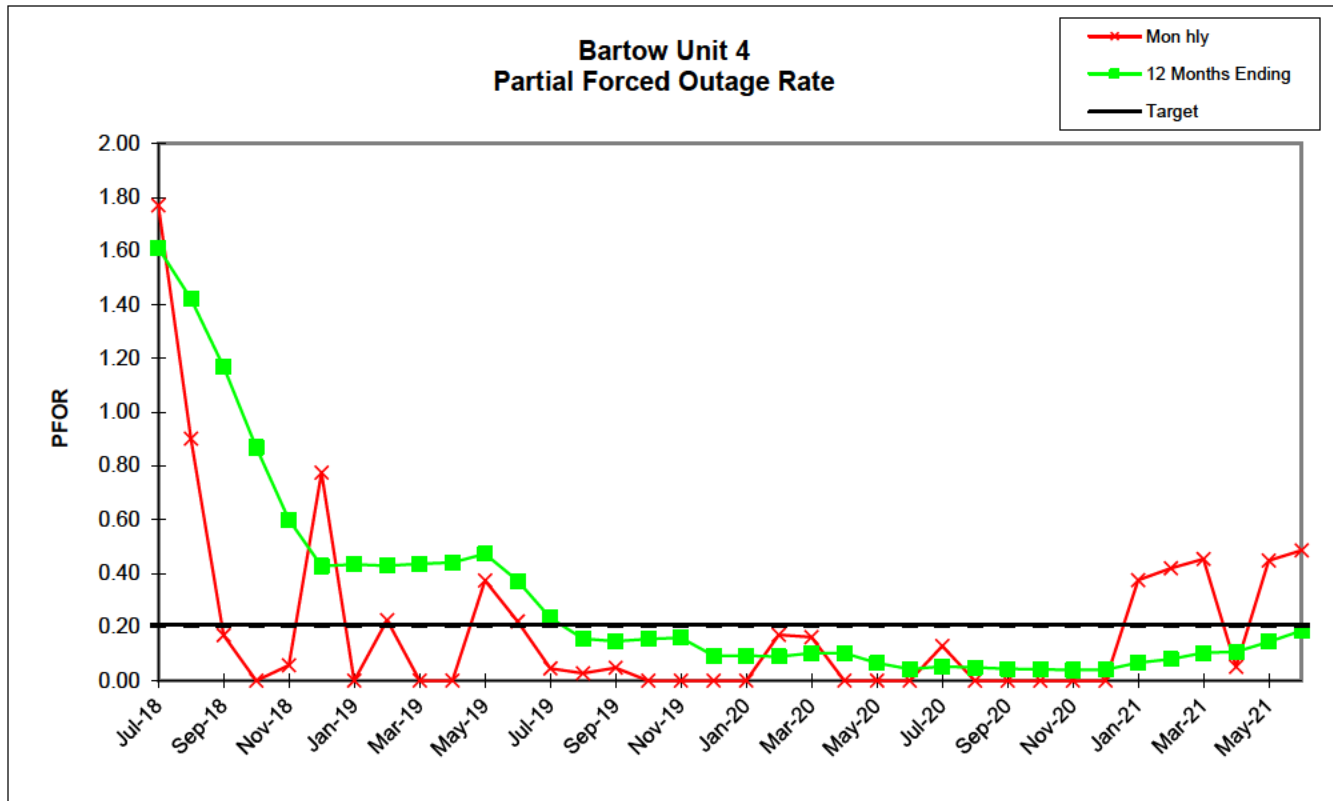
Bartow
Unit 4

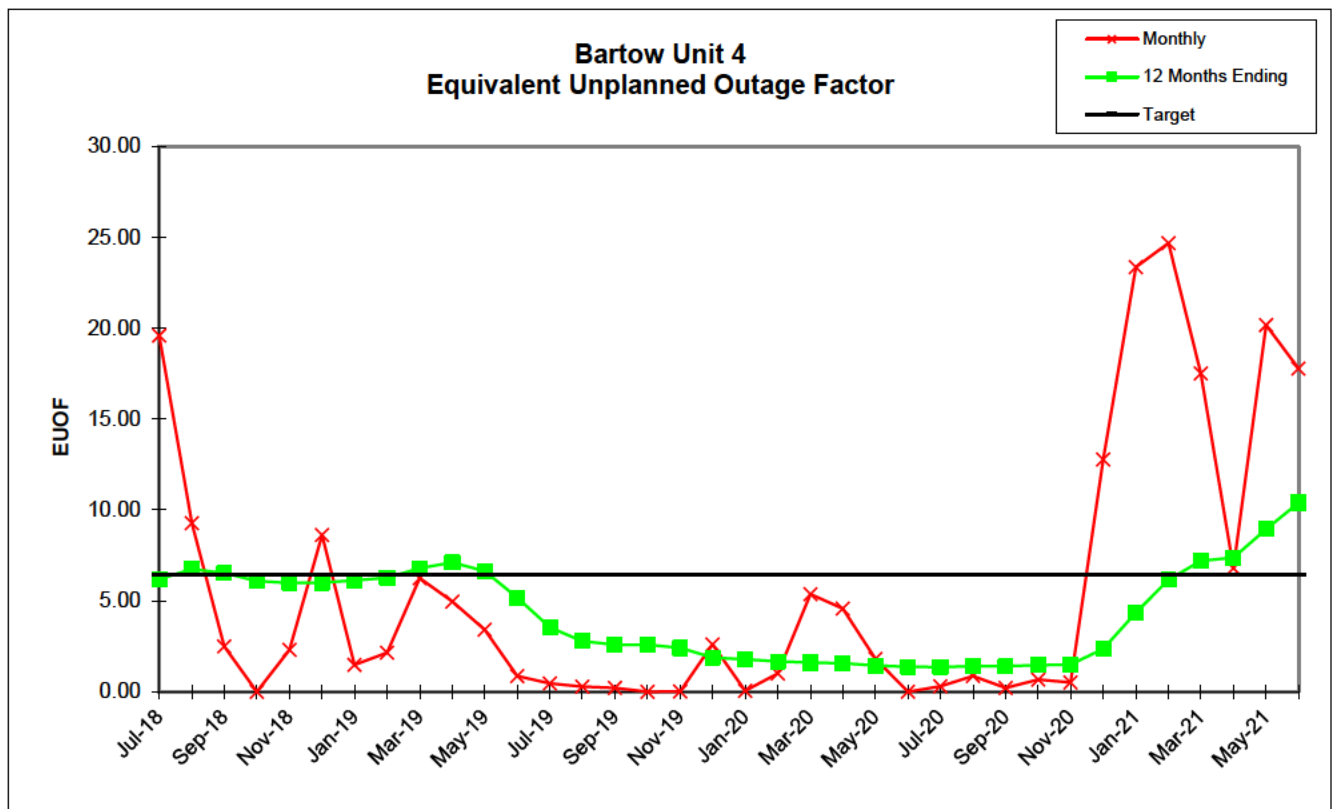
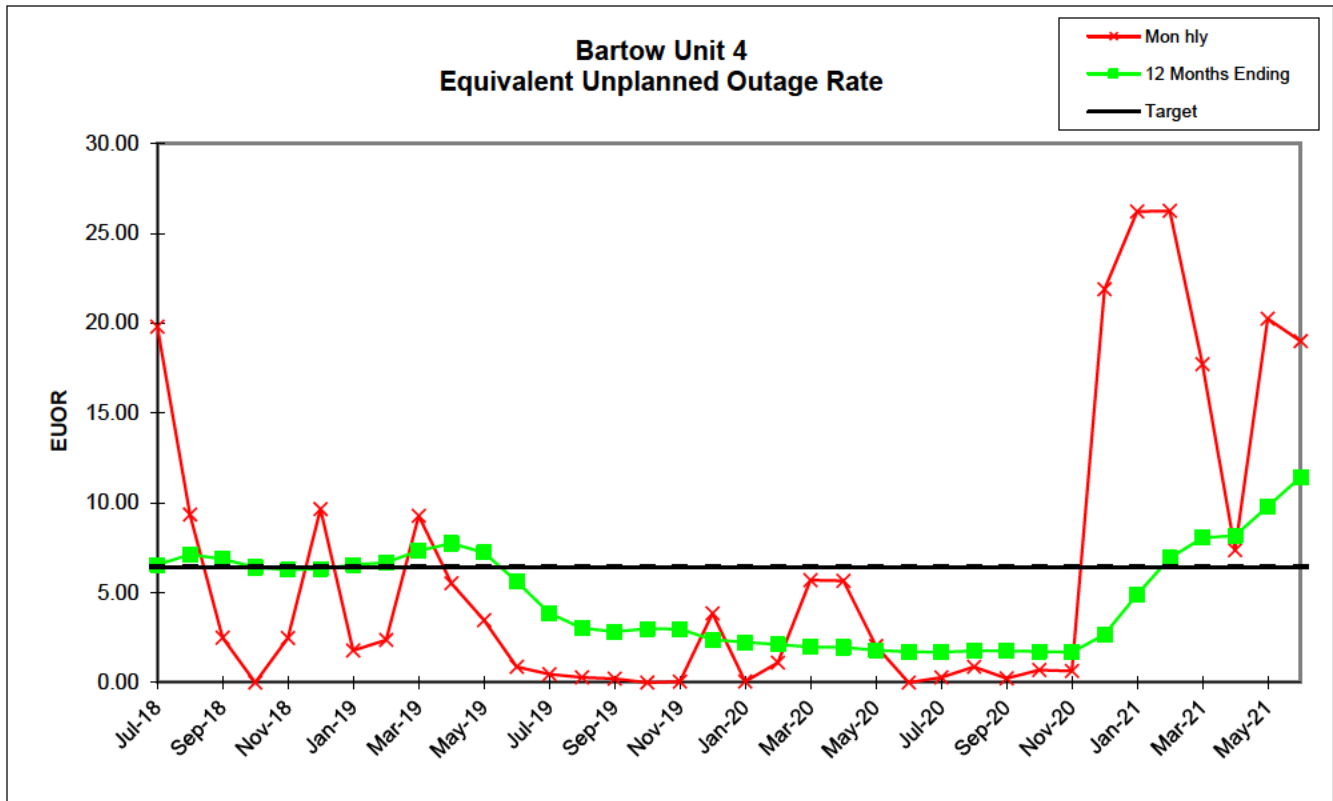
	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	601.19	675.79	702.70	708.62	654.33	605.85	603.93	593.93	485.47	612.30	711.99	695.10	737.09	740.57	670.41	278.80	189.58	483.51
RSH	7.57	5.18	0.51	35.38	23.94	55.22	129.04	65.02	8.72	1.31	12.29	20.24	4.23	1.78	23.79	7.57	48.81	71.93
UH	135.24	63.03	16.79	0.00	42.73	82.93	11.03	13.05	248.81	106.39	19.72	4.66	2.68	1.65	25.80	457.63	482.61	188.56
POH	0.00	0.00	0.00	0.00	27.77	23.38	0.00	0.00	234.02	70.58	0.00	0.00	0.00	0.00	24.63	457.63	482.51	169.16
FOH	135.24	63.03	6.61	0.00	3.35	41.02	8.52	13.05	0.00	14.09	9.17	4.66	1.22	0.73	1.17	0.00	0.10	0.00
MOH	0.00	0.00	10.18	0.00	11.61	18.53	2.51	0.00	14.79	21.72	10.55	0.00	1.46	0.92	0.00	0.00	0.00	19.40
PFOH	247.90	139.46	19.28	0.00	6.06	75.65	0.00	21.61	0.00	0.00	15.36	24.79	1.93	1.19	1.84	0.00	0.00	0.00
LRPF	46.36	47.15	66.99	0.00	67.04	67.00	0.00	66.98	0.00	0.00	186.98	67.00	186.77	187.05	187.58	0.00	0.00	0.00
EFOH	10.64	6.09	1.20	0.00	0.38	4.69	0.00	1.34	0.00	0.00	2.66	1.54	0.33	0.21	0.32	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	21.27	0.00	0.00	0.00	182.68	0.00	17.83	0.00	2.32	1.53	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	67.00	0.00	0.00	0.00	187.00	0.00	187.01	0.00	187.23	187.30	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	1.32	0.00	0.00	0.00	31.63	0.00	3.09	0.00	0.40	0.27	0.00	0.00	0.00	0.00
NPC	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00
MONTHLY	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	18.36	8.53	0.93	0.00	0.51	6.34	1.39	2.15	0.00	2.25	1.27	0.67	0.17	0.10	0.17	0.00	0.05	0.00
MOR	0.00	0.00	1.43	0.00	1.74	2.97	0.41	0.00	2.96	3.43	1.46	0.00	0.20	0.12	0.00	0.00	0.00	3.86
PFOR	1.77	0.90	0.17	0.00	0.06	0.77	0.00	0.23	0.00	0.00	0.37	0.22	0.05	0.03	0.05	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.00	6.52	0.00	0.43	0.00	0.05	0.04	0.00	0.00	0.00	0.00
EUOR	19.81	9.36	2.50	0.00	2.49	9.65	1.79	2.37	9.28	5.53	3.48	0.89	0.46	0.29	0.22	0.00	0.05	3.86
EUOF	19.61	9.29	2.50	0.00	2.31	8.63	1.48	2.14	6.25	4.97	3.42	0.86	0.46	0.29	0.21	0.00	0.01	2.61
POF	0.00	0.00	0.00	0.00	3.85	3.14	0.00	0.00	31.50	9.80	0.00	0.00	0.00	0.00	3.42	61.51	66.92	22.74
EAF	80.39	90.71	97.50	100.00	93.84	88.22	98.52	97.86	62.26	85.22	96.58	99.14	99.54	99.71	96.37	38.49	33.06	74.66
12 MONTHS	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	4.23	5.00	4.98	4.97	4.95	5.46	5.63	5.77	5.86	6.01	5.28	3.76	2.07	1.29	1.23	1.30	1.34	0.77
MOR	0.87	0.87	0.89	0.70	0.83	0.51	0.55	0.55	0.75	1.05	1.18	1.16	1.16	1.16	1.04	1.10	1.01	1.04
PFOR	1.61	1.42	1.17	0.87	0.60	0.43	0.43	0.43	0.44	0.44	0.47	0.37	0.23	0.16	0.15	0.16	0.16	0.09
PMOR	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.02	0.43	0.44	0.48	0.47	0.47	0.47	0.47	0.50	0.51	0.52
EUOR	6.56	7.13	6.89	6.42	6.28	6.33	6.55	6.68	7.34	7.75	7.23	5.64	3.86	3.03	2.84	3.00	2.97	2.39
EUOF	6.21	6.75	6.54	6.09	5.98	6.00	6.13	6.27	6.79	7.12	6.65	5.17	3.55	2.78	2.59	2.59	2.41	1.89
POF	2.24	2.24	2.24	2.24	1.94	1.86	1.86	1.86	3.26	4.06	4.06	4.06	4.06	4.06	4.34	9.57	14.76	16.42
EAF	91.55	91.01	91.22	91.67	92.07	92.14	92.01	91.87	89.95	88.82	89.29	90.77	92.39	93.16	93.06	87.84	82.84	81.69

Bartow
Unit 4

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	615.84	621.13	660.96	549.05	654.16	691.89	742.62	730.42	669.45	699.46	566.56	339.46	491.21	468.06	606.84	613.66	593.61	548.13
RSH	8.61	68.95	43.16	137.94	78.46	28.11	0.13	7.17	48.98	39.60	116.68	50.04	80.70	39.97	8.69	0.66	0.00	0.00
UH	119.55	5.92	38.88	33.01	11.38	0.00	1.25	6.41	1.57	4.94	37.76	354.50	172.09	163.97	127.47	105.68	150.39	171.87
POH	119.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.04	259.34	0.00	0.00	0.00	57.08	2.92	46.51
FOH	0.38	5.67	34.52	1.74	0.03	0.00	1.25	6.41	1.57	4.94	3.72	95.16	172.09	115.29	127.47	48.60	147.47	112.66
MOH	0.00	0.25	4.36	31.27	11.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.68	0.00	0.00	0.00	12.69
PFOH	0.00	11.24	11.37	0.00	0.06	0.00	19.92	0.00	0.00	0.00	0.00	0.00	165.67	223.62	247.24	28.33	238.62	239.59
LRPF	0.00	108.20	108.23	0.00	105.50	0.00	55.26	0.00	0.00	0.00	0.00	0.00	13.00	10.24	13.00	12.98	13.00	13.00
EFOH	0.00	1.06	1.08	0.00	0.01	0.00	0.96	0.00	0.00	0.00	0.00	0.00	1.84	1.96	2.75	0.31	2.65	2.66
PMOH	0.00	0.00	0.00	0.00	21.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	114.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	2.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	1144.00	1144.00	1144.00	1144.00	1144.00	1144.00	1144.00	1144.00	1144.00	1144.00	1144.00	1144.00	1169.00	1169.00	1169.00	1169.00	1169.00	1169.00
MONTHLY	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	0.06	0.90	4.96	0.32	0.00	0.00	0.17	0.87	0.23	0.70	0.65	21.89	25.94	19.76	17.36	7.34	19.90	17.05
MOR	0.00	0.04	0.66	5.39	1.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.42	0.00	0.00	0.00	2.26
PFOR	0.00	0.17	0.16	0.00	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.38	0.42	0.45	0.05	0.45	0.49
PMOR	0.00	0.00	0.00	0.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.06	1.11	5.71	5.67	2.04	0.00	0.30	0.87	0.23	0.70	0.65	21.89	26.22	26.25	17.73	7.39	20.26	19.01
EUOF	0.05	1.00	5.38	4.58	1.82	0.00	0.30	0.86	0.22	0.66	0.52	12.79	23.38	24.69	17.53	6.79	20.18	17.78
POF	16.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.72	34.86	0.00	0.00	0.00	7.93	0.39	6.46
EAF	83.93	99.00	94.62	95.42	98.18	100.00	99.70	99.14	99.78	99.34	94.76	52.35	76.62	75.31	82.47	85.28	79.43	75.76
12 MONTHS	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	0.65	0.54	1.01	0.85	0.72	0.66	0.66	0.74	0.74	0.77	0.78	2.02	4.22	5.67	6.84	7.34	9.12	10.58
MOR	1.00	1.00	0.83	0.97	0.99	0.99	0.97	0.96	0.96	0.90	0.86	0.62	0.63	1.30	1.25	0.82	0.67	0.86
PFOR	0.09	0.09	0.10	0.10	0.07	0.04	0.05	0.05	0.05	0.04	0.04	0.04	0.07	0.08	0.10	0.11	0.15	0.19
PMOR	0.52	0.52	0.05	0.05	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.00
EUOR	2.24	2.13	1.98	1.96	1.80	1.72	1.70	1.76	1.76	1.73	1.69	2.68	4.90	6.93	8.05	8.17	9.81	11.44
EUOF	1.77	1.68	1.61	1.58	1.44	1.37	1.36	1.41	1.41	1.46	1.50	2.37	4.34	6.17	7.20	7.38	8.94	10.40
POF	17.78	17.73	15.07	14.27	14.27	14.27	14.27	14.27	13.99	8.78	3.67	4.70	3.34	3.35	3.35	4.00	4.03	4.57
EAF	80.45	80.58	83.32	84.16	84.29	84.36	84.38	84.33	84.61	89.76	94.83	92.94	92.32	90.48	89.45	88.62	87.03	85.03





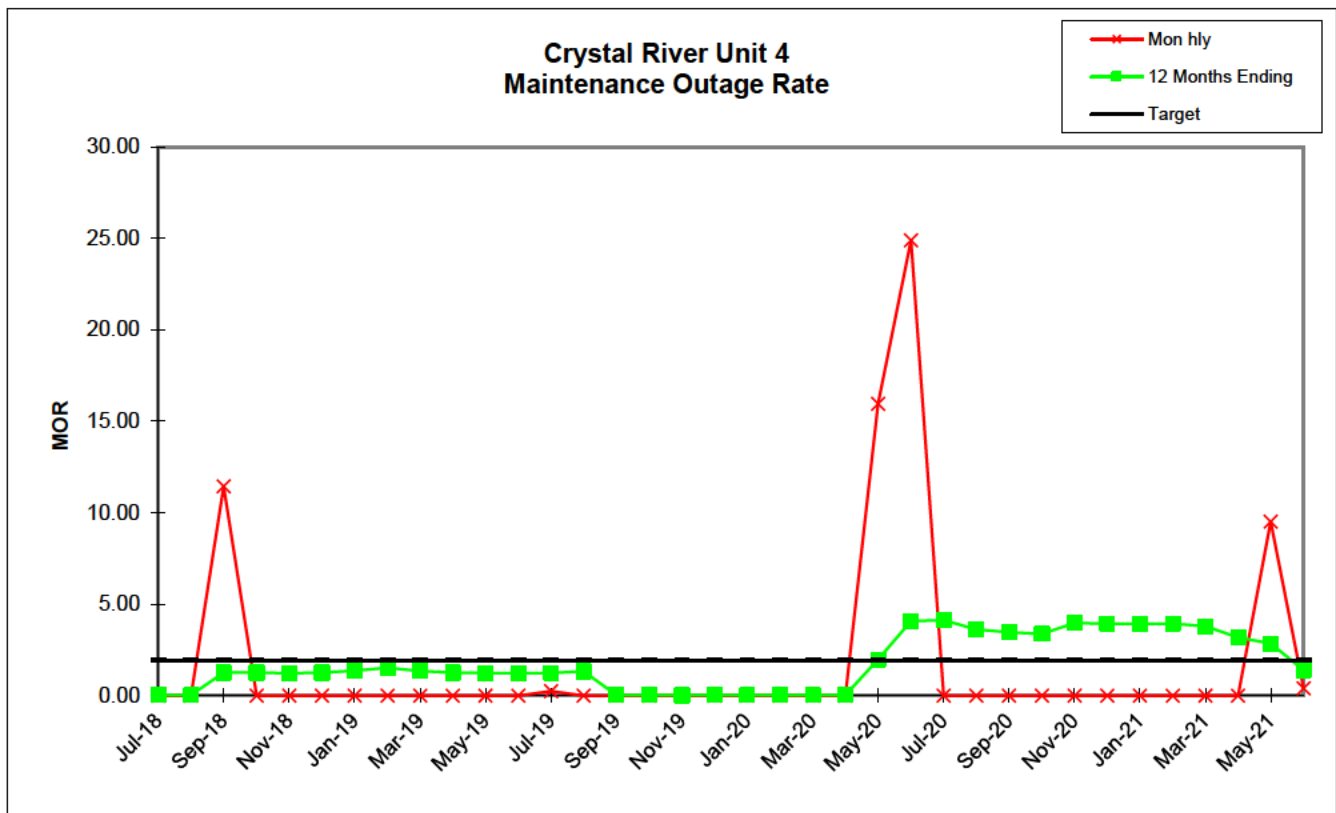
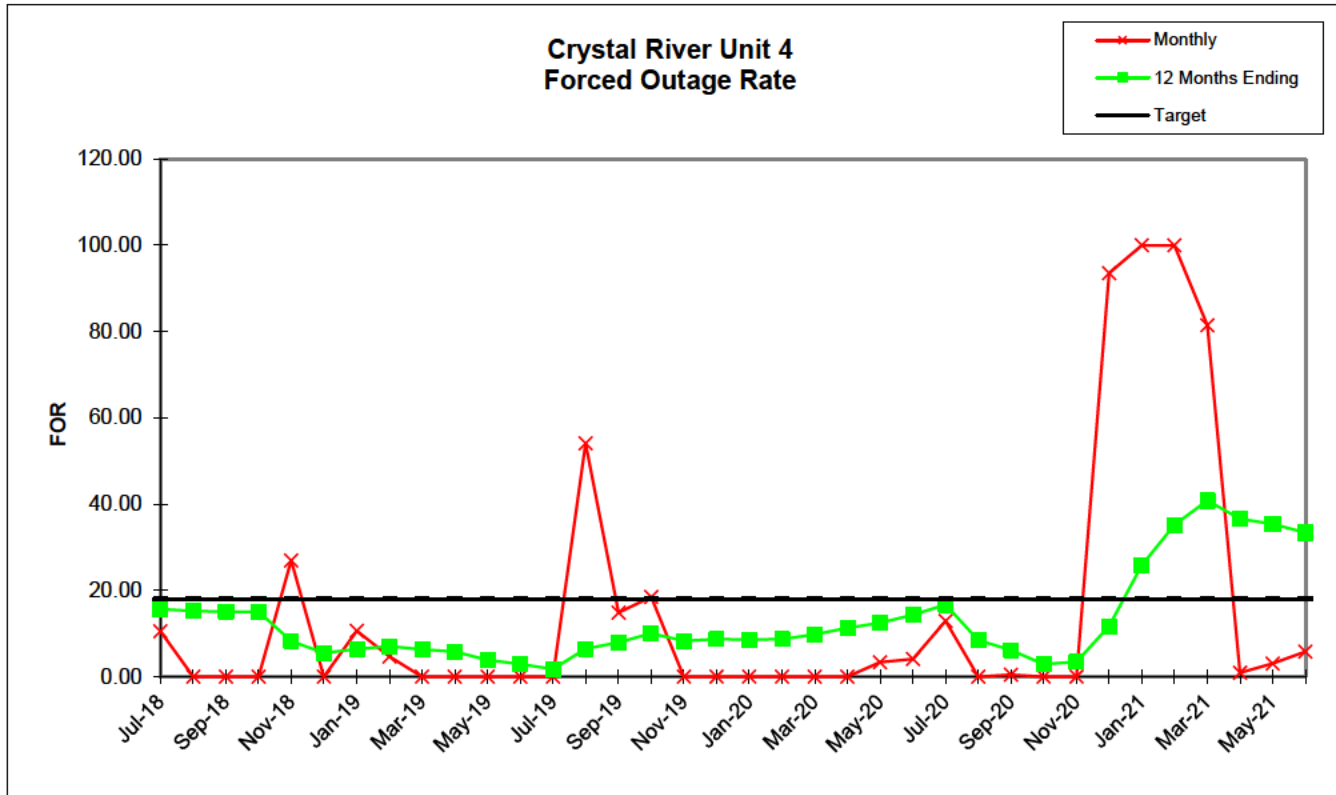


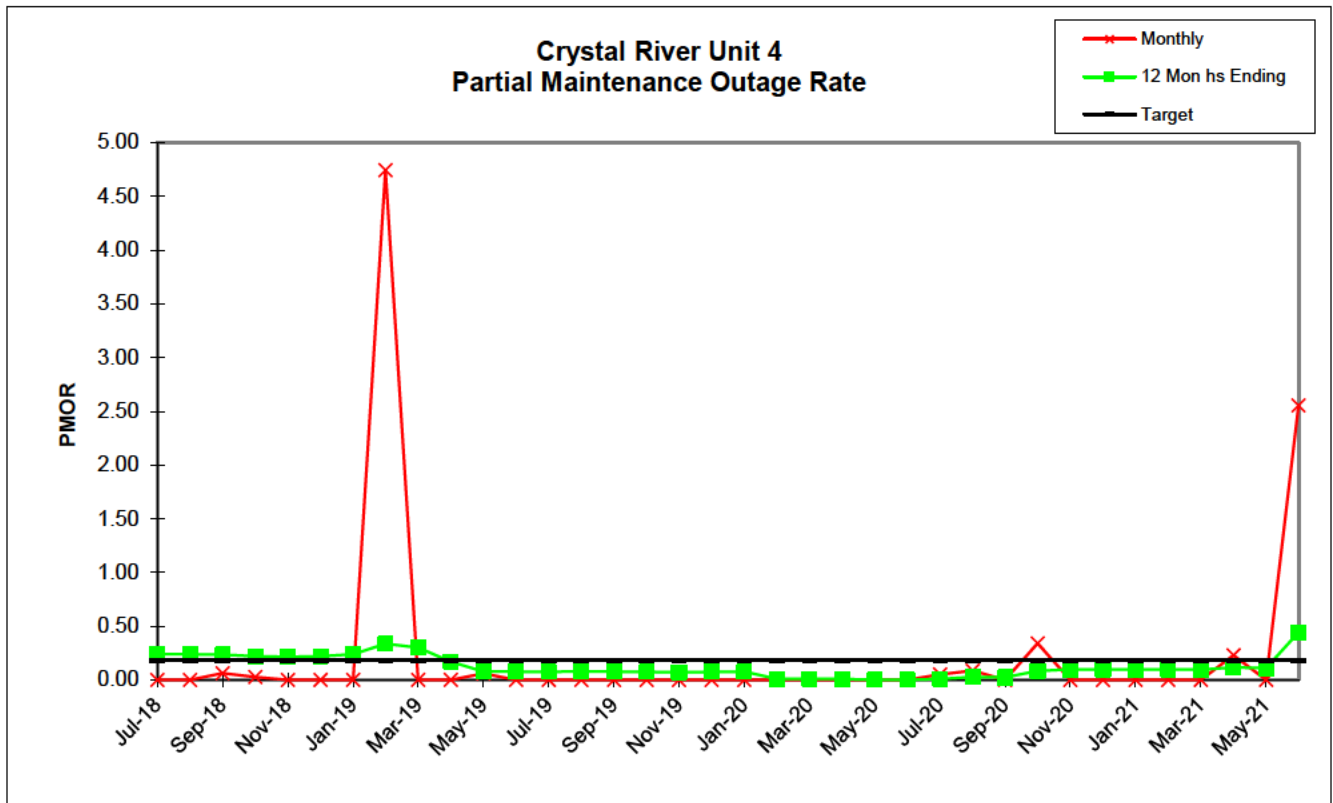
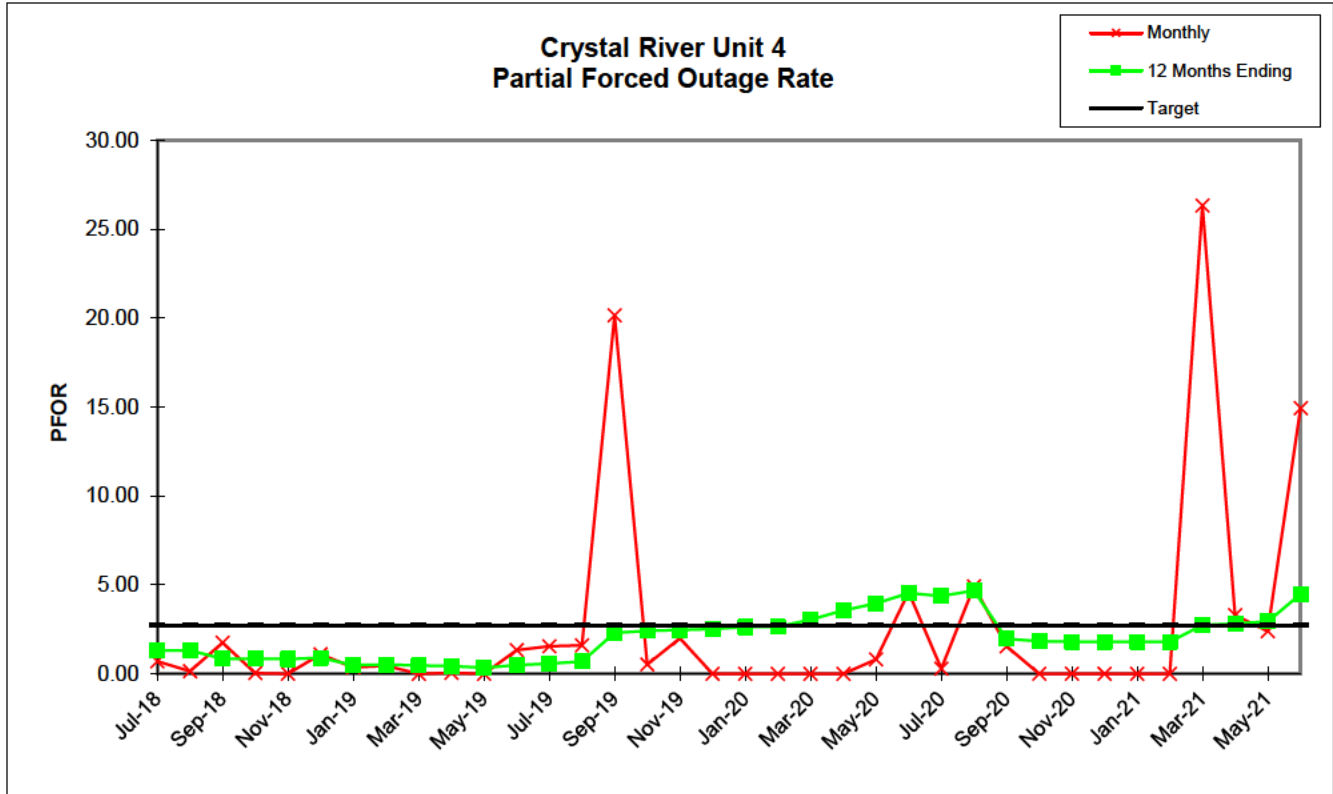
Crystal River
Unit 4

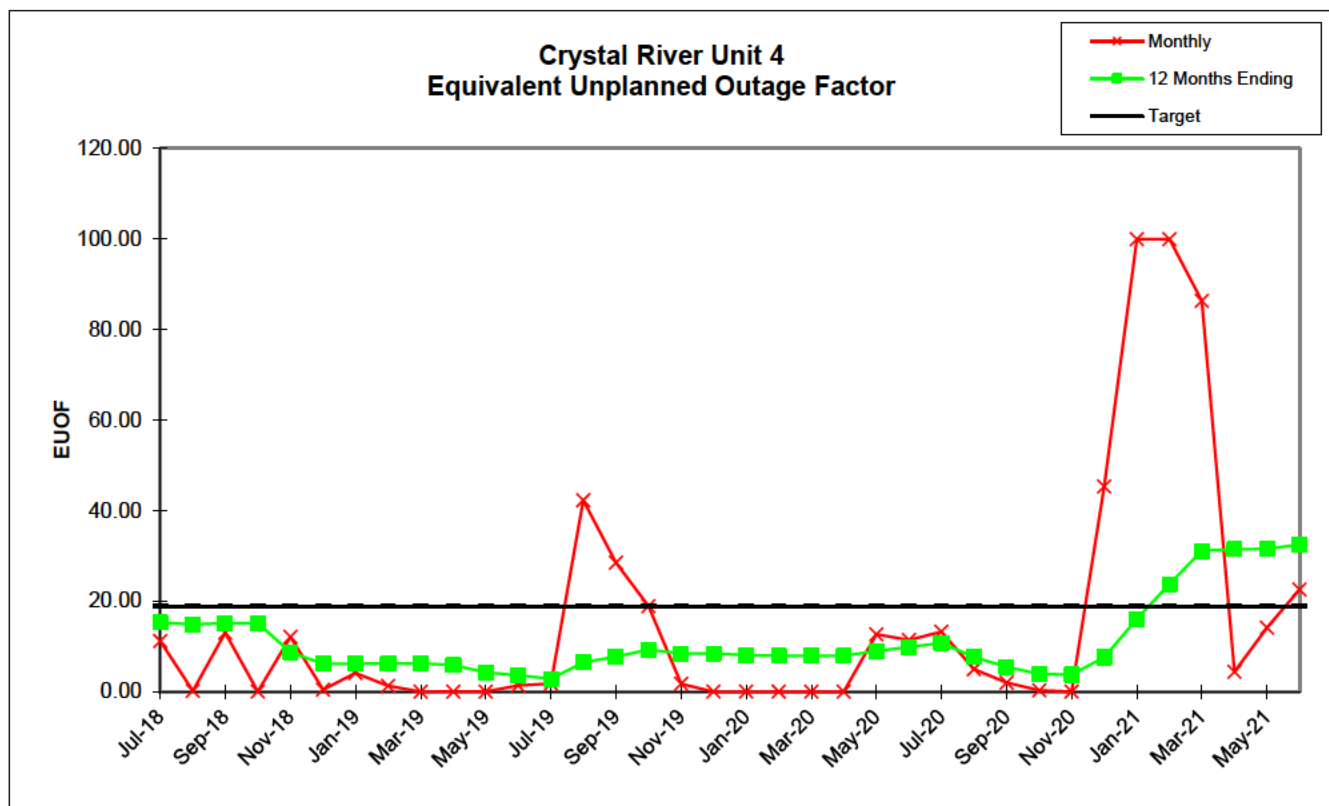
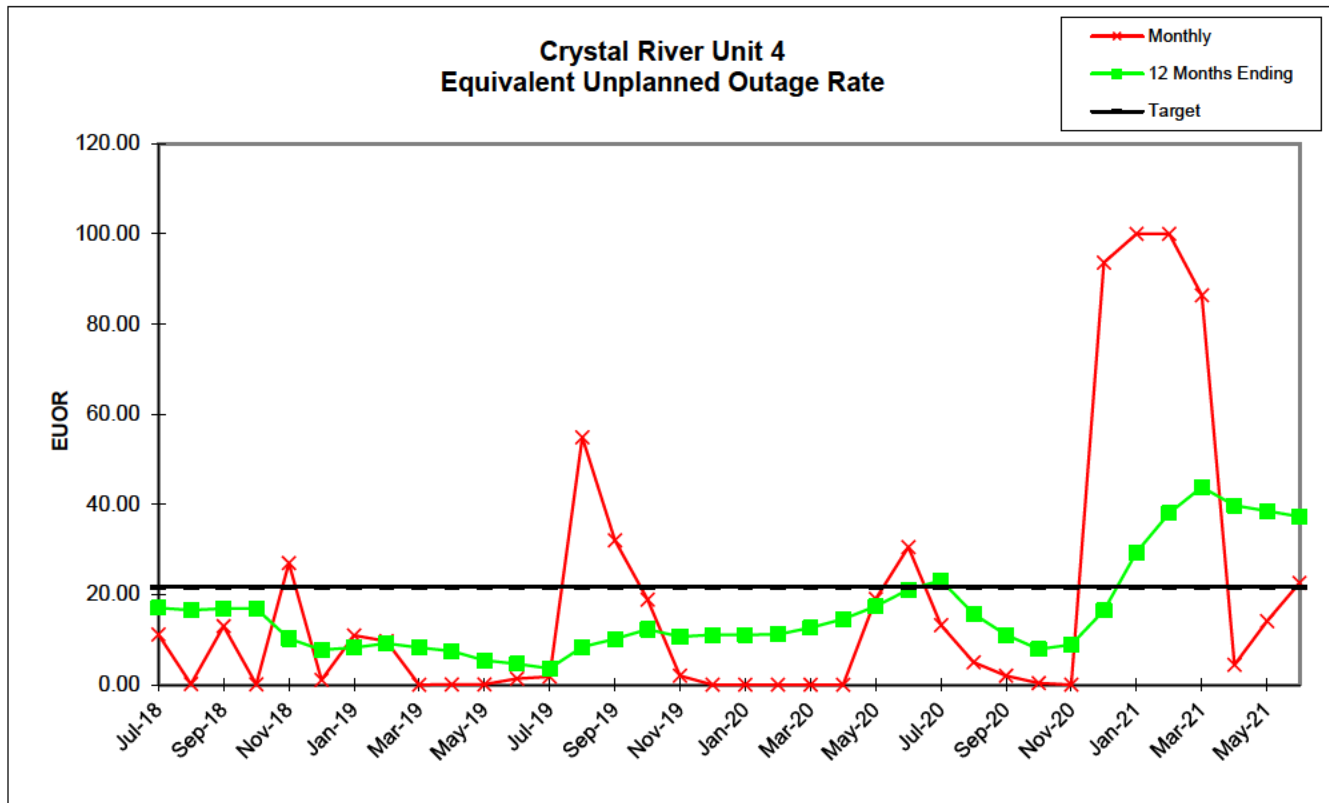
	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	665.55	744.00	637.70	744.00	236.67	313.82	248.95	85.33	743.00	720.00	744.00	720.00	742.15	263.35	545.87	606.38	627.60	0.00
RSH	0.00	0.00	0.00	0.00	247.98	414.50	465.47	582.43	0.00	0.00	0.00	0.00	0.00	169.83	79.07	0.00	69.42	264.00
UH	78.45	0.00	82.30	0.00	236.35	15.68	29.58	4.23	0.00	0.00	0.00	0.00	1.85	310.82	95.07	137.62	23.98	480.00
POH	0.00	0.00	0.00	0.00	148.98	15.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.98	480.00
FOH	78.45	0.00	0.00	0.00	87.37	0.00	29.58	4.23	0.00	0.00	0.00	0.00	0.00	310.82	95.07	137.62	0.00	0.00
MOH	0.00	0.00	82.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.85	0.00	0.00	0.00	0.00	0.00
PFOH	20.43	8.08	125.70	2.00	0.00	11.73	2.23	2.90	0.00	1.65	0.00	70.00	71.48	17.58	525.63	9.70	38.80	0.00
LRPF	161.37	99.47	63.14	93.00	0.00	209.88	284.43	93.00	0.00	188.00	0.00	98.19	115.21	171.04	149.10	231.94	231.13	0.00
EFOH	4.63	1.13	11.15	0.26	0.00	3.46	0.89	0.38	0.00	0.44	0.00	9.65	11.57	4.22	110.07	3.16	12.60	0.00
PMOH	0.00	0.00	3.00	0.50	0.00	0.00	0.00	31.00	0.00	0.00	3.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	93.00	284.00	0.00	0.00	0.00	93.00	0.00	0.00	93.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.39	0.20	0.00	0.00	0.00	4.05	0.00	0.00	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00
MONTHLY	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	10.54	0.00	0.00	0.00	26.96	0.00	10.62	4.72	0.00	0.00	0.00	0.00	0.00	54.13	14.83	18.50	0.00	0.00
MOR	0.00	0.00	11.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.00	0.00
PFOR	0.70	0.15	1.75	0.04	0.00	1.10	0.36	0.44	0.00	0.06	0.00	1.34	1.56	1.60	20.17	0.52	2.01	0.00
PMOR	0.00	0.00	0.06	0.03	0.00	0.00	0.00	4.75	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	11.17	0.15	13.03	0.06	26.96	1.10	10.94	9.67	0.00	0.06	0.06	1.34	1.80	54.87	32.01	18.92	2.01	0.00
EUOF	11.17	0.15	13.03	0.06	12.12	0.46	4.10	1.29	0.00	0.06	0.06	1.34	1.80	42.34	28.49	18.92	1.75	0.00
POF	0.00	0.00	0.00	0.00	20.66	2.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.33	64.52
EAF	88.83	99.85	86.97	99.94	67.22	97.43	95.90	98.71	100.00	99.94	99.94	98.66	98.20	57.66	71.51	81.08	94.93	35.48
12 MONTHS	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	15.71	15.22	15.07	15.07	8.27	5.55	6.40	7.11	6.36	5.80	3.90	2.93	1.78	6.51	7.94	10.02	8.32	8.72
MOR	0.03	0.03	1.26	1.26	1.23	1.27	1.37	1.52	1.35	1.27	1.24	1.23	1.24	1.34	0.03	0.03	0.03	0.03
PFOR	1.32	1.31	0.85	0.85	0.83	0.91	0.48	0.52	0.46	0.44	0.34	0.48	0.58	0.68	2.31	2.41	2.46	2.53
PMOR	0.24	0.24	0.24	0.22	0.21	0.22	0.24	0.34	0.30	0.17	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
EUOR	17.05	16.56	16.89	16.88	10.25	7.73	8.27	9.21	8.25	7.49	5.45	4.63	3.62	8.39	10.16	12.28	10.66	11.12
EUOF	15.28	14.84	15.14	15.13	8.73	6.20	6.19	6.28	6.28	5.89	4.28	3.64	2.85	6.43	7.70	9.30	8.45	8.41
POF	10.35	10.35	10.35	10.35	12.05	12.23	12.23	12.23	4.29	1.88	1.88	1.88	1.88	1.88	1.88	1.88	0.45	5.75
EAF	74.37	74.81	74.51	74.52	79.23	81.57	81.58	81.49	89.43	92.23	93.84	94.48	95.27	91.69	90.42	88.82	91.10	85.84

Crystal River
Unit 4

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	0.00	0.00	0.00	0.00	404.67	196.20	647.63	744.00	716.50	721.77	0.00	23.06	0.00	0.00	137.61	713.30	654.48	675.62
RSH	744.00	336.00	0.00	0.00	50.90	450.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	360.00	743.00	720.00	288.43	73.40	96.37	0.00	3.50	22.23	721.00	720.94	744.00	672.00	605.39	6.70	89.52	44.38
POH	0.00	360.00	743.00	720.00	197.58	0.00	0.00	0.00	0.00	22.23	721.00	383.27	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	14.08	8.40	96.37	0.00	3.50	0.00	0.00	337.67	744.00	672.00	605.39	6.70	20.70	41.60
MOH	0.00	0.00	0.00	0.00	76.77	65.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.82	2.78
PFOH	0.00	0.00	0.00	0.00	42.02	28.62	10.63	95.62	47.68	0.00	0.00	0.00	0.00	0.00	72.93	91.55	86.17	235.63
LRPF	0.00	0.00	0.00	0.00	56.18	223.83	127.93	272.31	166.80	0.00	0.00	0.00	0.00	0.00	353.71	182.84	129.39	305.13
EFOH	0.00	0.00	0.00	0.00	3.32	9.00	1.91	36.57	11.17	0.00	0.00	0.00	0.00	0.00	36.23	23.51	15.66	100.98
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	2.50	5.00	0.00	15.75	0.00	0.00	0.00	0.00	0.00	12.58	0.00	37.60
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	91.14	92.56	0.00	110.76	0.00	0.00	0.00	0.00	0.00	92.82	0.00	326.84
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.32	0.65	0.00	2.45	0.00	0.00	0.00	0.00	0.00	1.64	0.00	17.26
NPC	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00
MONTHLY	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	0.00	0.00	0.00	0.00	3.36	4.11	12.95	0.00	0.49	0.00	0.00	93.61	100.00	100.00	81.48	0.93	3.07	5.80
MOR	0.00	0.00	0.00	0.00	15.95	24.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.51	0.41
PFOR	0.00	0.00	0.00	0.00	0.82	4.59	0.29	4.92	1.56	0.00	0.00	0.00	0.00	0.00	26.33	3.30	2.39	14.95
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.09	0.00	0.34	0.00	0.00	0.00	0.00	0.00	0.23	0.00	2.55
EUOR	0.00	0.00	0.00	0.00	19.00	30.56	13.25	5.00	2.04	0.34	0.00	93.61	100.00	100.00	86.36	4.42	14.14	22.59
EUOF	0.00	0.00	0.00	0.00	12.66	11.44	13.25	5.00	2.04	0.33	0.00	45.39	100.00	100.00	86.36	4.42	14.14	22.59
POF	0.00	51.72	100.00	100.00	26.56	0.00	0.00	0.00	0.00	2.99	100.00	51.51	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	48.28	0.00	0.00	60.79	88.56	86.75	95.00	97.96	96.68	0.00	3.10	0.00	0.00	13.64	95.58	85.86	77.41
12 MONTHS	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	8.63	8.69	9.86	11.34	12.48	14.32	16.75	8.52	6.19	2.93	3.44	11.75	25.85	35.20	40.86	36.63	35.39	33.43
MOR	0.03	0.03	0.04	0.04	1.97	4.07	4.13	3.62	3.47	3.38	3.97	3.94	3.94	3.94	3.80	3.19	2.85	1.40
PFOR	2.62	2.66	3.05	3.56	3.95	4.55	4.38	4.68	1.97	1.84	1.81	1.79	1.79	1.79	2.73	2.83	2.94	4.49
PMOR	0.08	0.01	0.01	0.01	0.00	0.00	0.01	0.03	0.02	0.08	0.10	0.10	0.10	0.10	0.10	0.12	0.11	0.44
EUOR	11.13	11.15	12.65	14.54	17.39	21.08	23.16	15.73	11.06	7.91	8.92	16.45	29.40	38.07	43.84	39.75	38.53	37.31
EUOF	8.06	7.94	7.94	7.94	9.00	9.83	10.80	7.64	5.47	3.89	3.75	7.60	16.07	23.78	31.10	31.47	31.59	32.51
POF	5.75	9.84	18.29	26.49	28.74	28.74	28.74	28.74	28.74	28.99	36.93	35.83	35.83	31.82	23.33	15.12	12.86	12.86
EAF	86.19	82.22	73.76	65.57	62.26	61.43	60.46	63.62	65.79	67.11	59.32	56.58	48.11	44.40	45.56	53.42	55.55	54.63





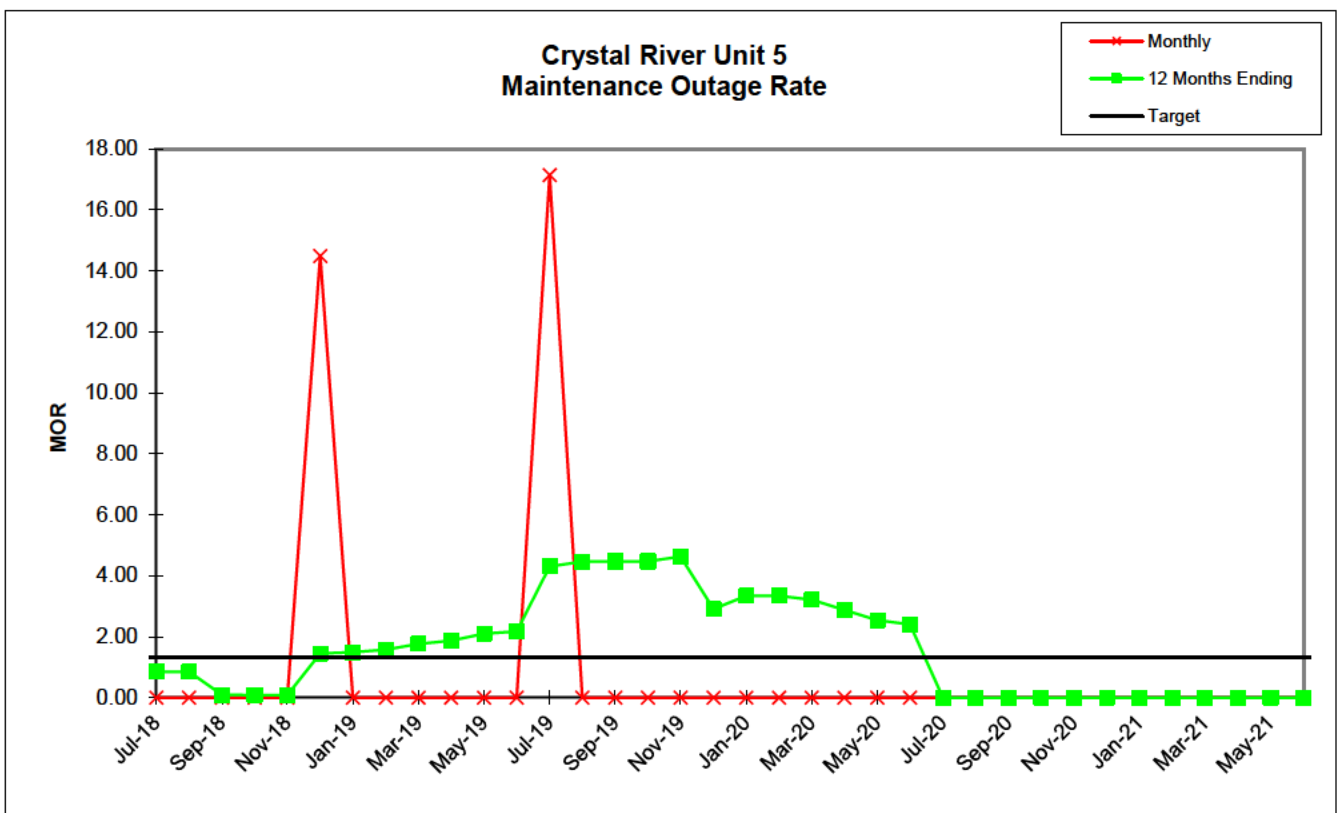
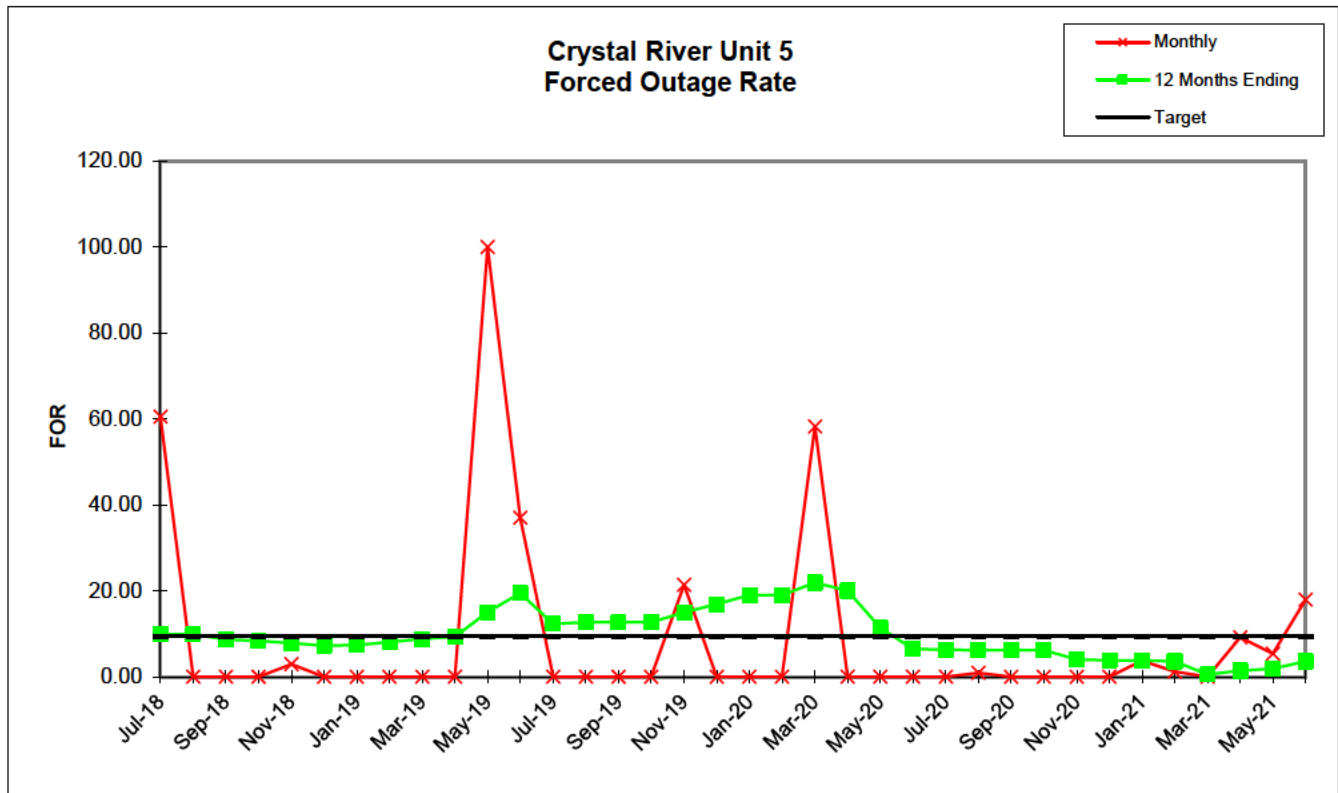


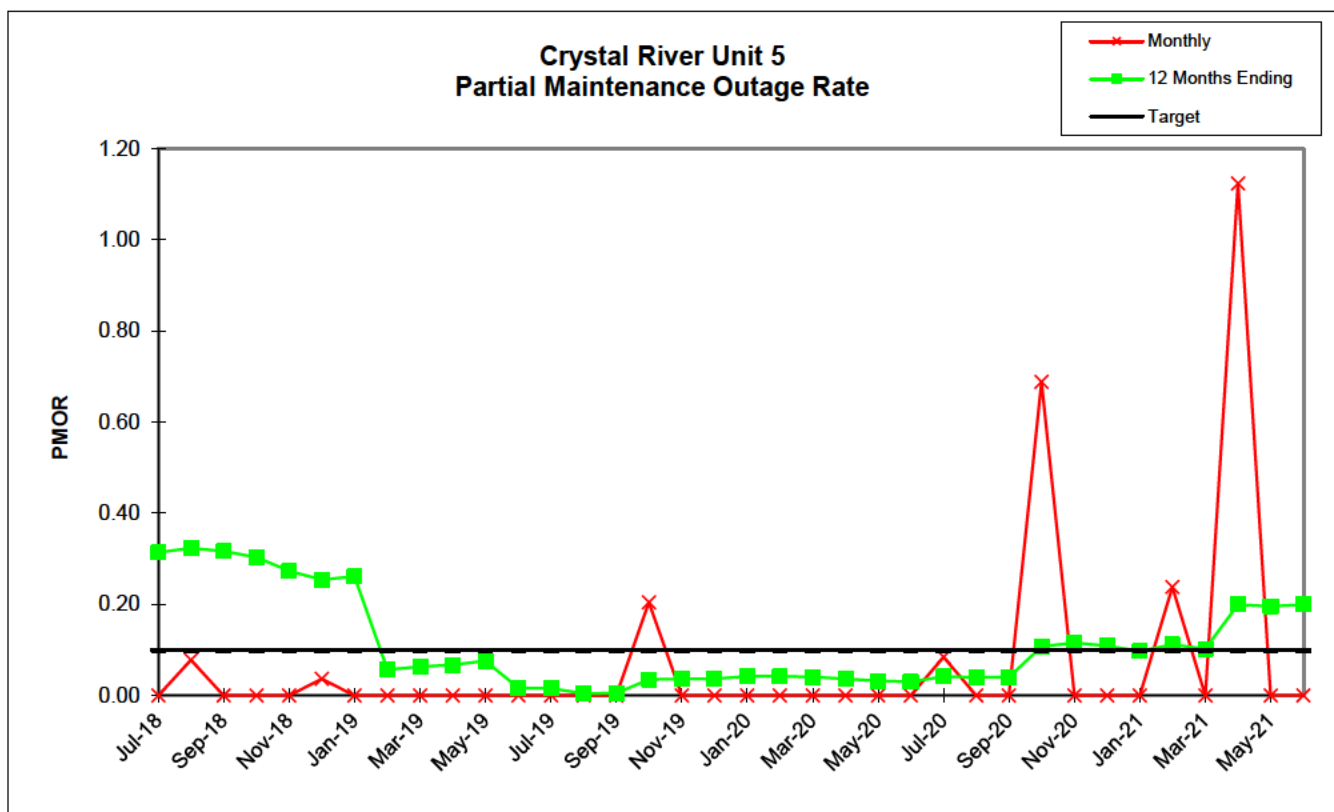
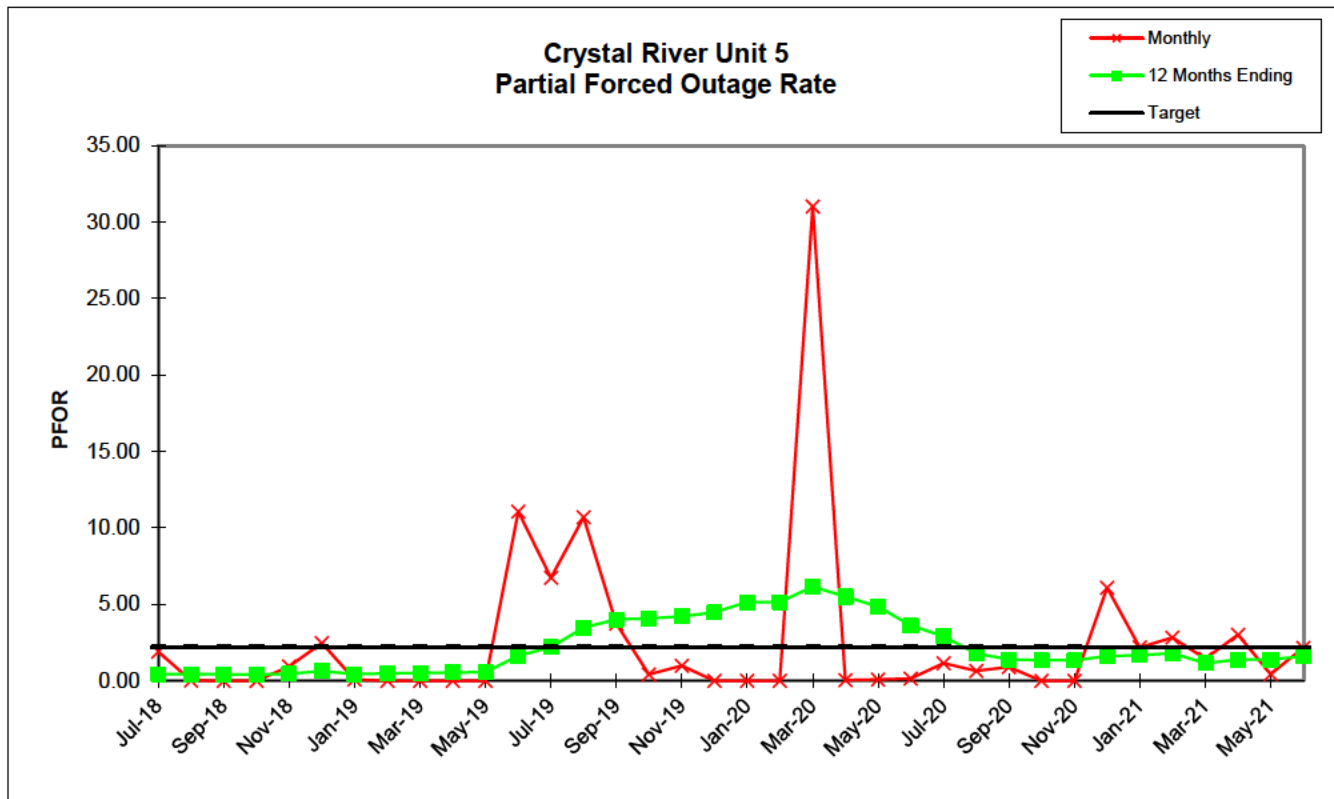
Crystal River
Unit 5

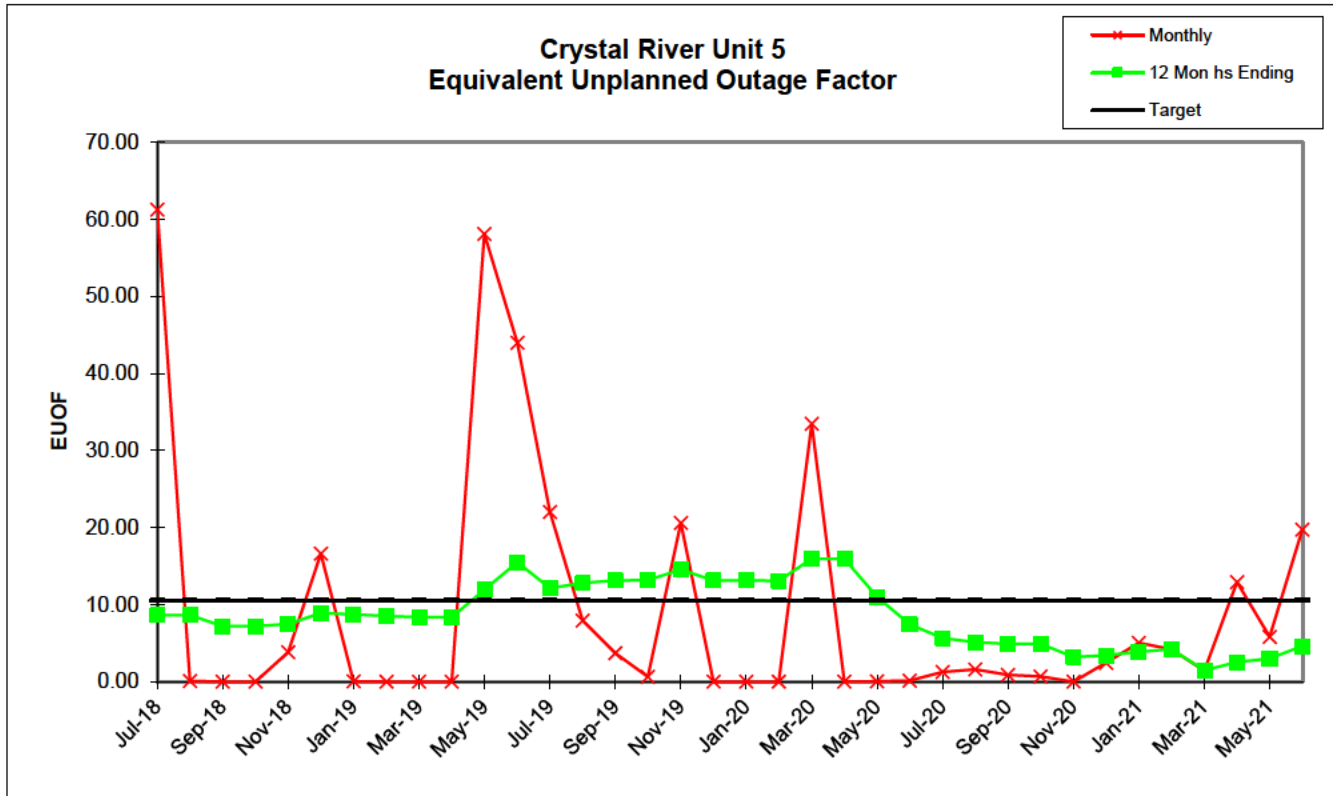
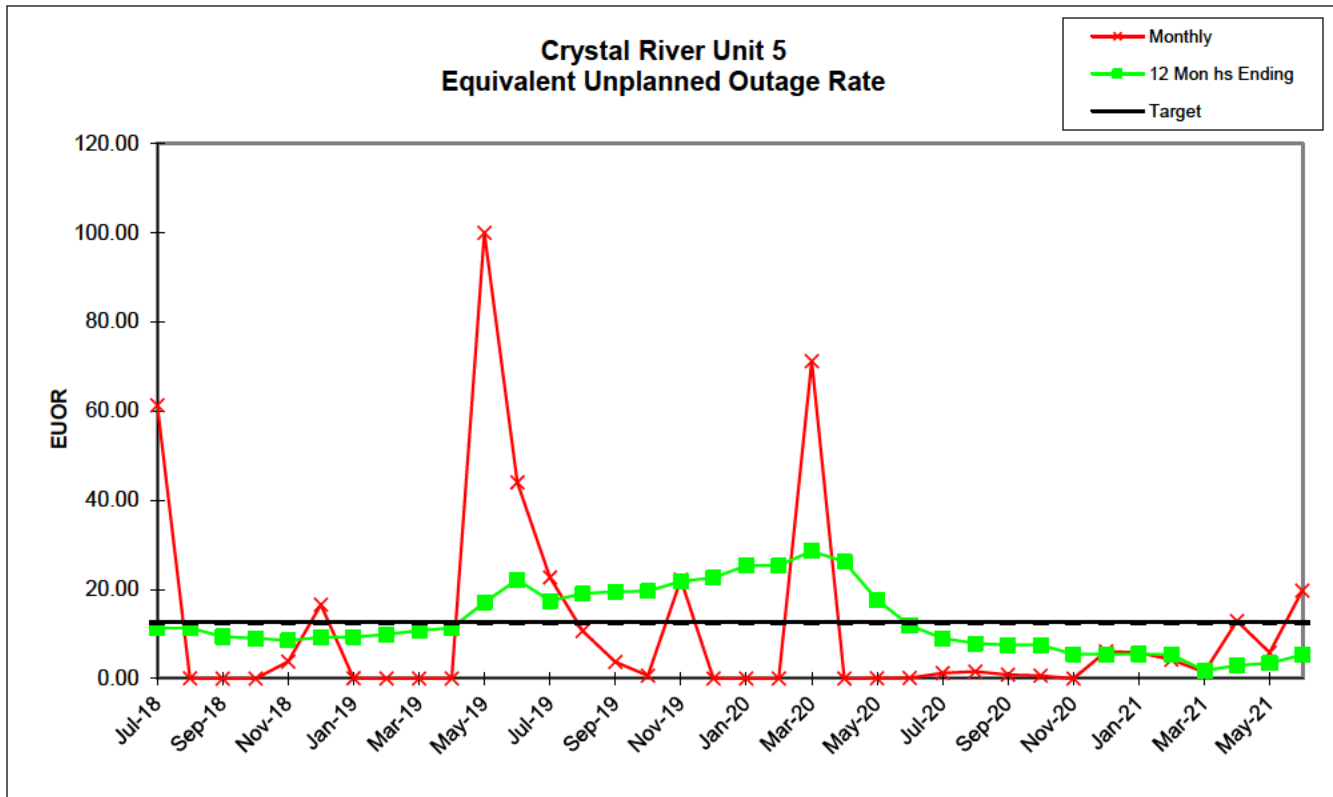
	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	293.52	744.00	720.00	744.00	700.05	636.30	547.67	0.00	0.00	0.00	0.00	453.31	598.25	551.58	711.58	744.00	527.58	0.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	196.33	528.00	0.00	0.00	0.00	0.00	22.05	192.42	8.42	0.00	25.87	264.00
UH	450.48	0.00	0.00	0.00	20.95	107.70	0.00	144.00	743.00	720.00	743.60	266.68	123.70	0.00	0.00	0.00	167.55	480.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	144.00	743.00	720.00	311.02	0.00	0.00	0.00	0.00	0.00	23.98	480.00
FOH	450.48	0.00	0.00	0.00	20.95	0.00	0.00	0.00	0.00	0.00	432.58	266.68	0.00	0.00	0.00	0.00	143.57	0.00
MOH	0.00	0.00	0.00	0.00	0.00	107.70	0.00	0.00	0.00	0.00	0.00	0.00	123.70	0.00	0.00	0.00	0.00	0.00
PFOH	16.76	1.50	0.00	0.00	19.48	59.37	1.00	0.00	0.00	0.00	0.00	585.29	402.50	435.01	67.71	8.00	40.48	0.00
LRPF	236.17	53.00	0.00	0.00	240.51	187.77	377.00	0.00	0.00	0.00	0.00	60.85	71.16	96.33	280.42	282.00	91.01	0.00
EFOH	5.58	0.11	0.00	0.00	6.60	15.70	0.53	0.00	0.00	0.00	0.00	50.17	40.34	59.02	26.74	3.18	5.19	0.00
PMOH	0.00	4.52	0.00	0.00	0.00	1.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.00	0.00
LRPM	0.00	90.93	0.00	0.00	0.00	91.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	120.00	0.00	0.00
EMOH	0.00	0.58	0.00	0.00	0.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.52	0.00	0.00
NPC	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00
MONTHLY	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	60.55	0.00	0.00	0.00	2.91	0.00	0.00	0.00	0.00	0.00	100.00	37.04	0.00	0.00	0.00	0.00	21.39	0.00
MOR	0.00	0.00	0.00	0.00	0.00	14.48	0.00	0.00	0.00	0.00	0.00	0.00	17.13	0.00	0.00	0.00	0.00	0.00
PFOR	1.90	0.02	0.00	0.00	0.94	2.47	0.10	0.00	0.00	0.00	0.00	11.07	6.74	10.70	3.76	0.43	0.98	0.00
PMOR	0.00	0.08	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00
EUOR	61.30	0.09	0.00	0.00	3.82	16.62	0.10	0.00	0.00	0.00	100.00	44.01	22.72	10.70	3.76	0.63	22.16	0.00
EUOF	61.30	0.09	0.00	0.00	3.82	16.62	0.07	0.00	0.00	0.00	58.14	44.01	22.05	7.93	3.71	0.63	20.63	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.43	100.00	100.00	41.80	0.00	0.00	0.00	0.00	0.00	3.33	64.52
EAF	38.70	99.91	100.00	100.00	96.18	83.38	99.93	78.57	0.00	0.00	0.05	55.99	77.95	92.07	96.29	99.37	76.04	35.48
12 MONTHS	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	9.97	9.97	8.66	8.33	7.82	7.24	7.41	8.08	8.79	9.30	15.05	19.48	12.28	12.70	12.72	12.72	15.02	16.94
MOR	0.85	0.85	0.09	0.09	0.08	1.45	1.49	1.58	1.76	1.87	2.10	2.18	4.31	4.46	4.47	4.47	4.63	2.91
PFOR	0.44	0.43	0.43	0.41	0.46	0.63	0.45	0.49	0.51	0.54	0.57	1.63	2.21	3.48	4.03	4.09	4.21	4.48
PMOR	0.31	0.32	0.32	0.30	0.27	0.25	0.26	0.06	0.06	0.07	0.08	0.02	0.02	0.00	0.00	0.04	0.04	0.04
EUOR	11.33	11.33	9.42	9.06	8.57	9.30	9.34	9.91	10.77	11.39	17.10	22.20	17.49	19.05	19.53	19.61	21.85	22.61
EUOF	8.66	8.66	7.20	7.20	7.51	8.92	8.76	8.53	8.36	8.36	11.94	15.50	12.17	12.83	13.14	13.19	14.58	13.16
POF	23.57	23.57	23.57	20.55	12.32	4.01	4.01	5.66	14.14	18.34	21.90	21.90	21.90	21.90	21.90	21.90	22.17	27.65
EAF	67.77	67.77	69.23	72.25	80.16	87.06	87.23	85.81	77.50	73.30	66.16	62.60	65.94	65.27	64.97	64.91	63.26	59.19

Crystal River
Unit 5

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	0.00	0.00	145.98	442.75	573.57	720.00	744.00	737.07	720.00	744.00	144.90	302.00	615.02	664.00	743.00	654.02	703.70	590.52
RSH	744.00	696.00	393.43	277.25	170.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	104.98	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	203.58	0.00	0.00	0.00	0.00	6.93	0.00	0.00	576.10	442.00	24.00	8.00	0.00	65.98	40.30	129.48
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	576.10	442.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	203.58	0.00	0.00	0.00	0.00	6.93	0.00	0.00	0.00	0.00	24.00	8.00	0.00	65.98	40.30	129.48
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	92.08	2.50	5.50	22.33	19.23	28.25	29.23	0.00	0.00	92.98	33.75	61.55	24.90	91.72	12.93	77.40
LRPF	0.00	0.00	349.15	60.00	60.00	35.01	319.74	120.89	158.86	0.00	0.00	140.66	281.90	216.40	305.96	153.27	168.03	117.51
EFOH	0.00	0.00	45.28	0.21	0.46	1.10	8.66	4.81	6.54	0.00	0.00	18.42	13.40	18.76	10.73	19.80	3.06	12.81
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	18.48	0.00	0.00	0.00	11.00	0.00	18.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	89.46	0.00	0.00	196.71	0.00	0.00	0.00	101.98	0.00	289.92	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.63	0.00	0.00	5.12	0.00	0.00	0.00	1.58	0.00	7.35	0.00	0.00
NPC	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00
MONTHLY	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	0.00	0.00	58.24	0.00	0.00	0.00	0.00	0.93	0.00	0.00	0.00	0.00	3.76	1.19	0.00	9.16	5.42	17.98
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	31.02	0.05	0.08	0.15	1.16	0.65	0.91	0.00	0.00	6.10	2.18	2.83	1.44	3.03	0.43	2.17
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.69	0.00	0.00	0.00	0.24	0.00	1.12	0.00	0.00
EUOR	0.00	0.00	71.19	0.05	0.08	0.15	1.25	1.58	0.91	0.69	0.00	6.10	5.85	4.22	1.44	12.93	5.83	19.76
EUOF	0.00	0.00	33.49	0.03	0.06	0.15	1.25	1.58	0.91	0.69	0.00	2.48	5.03	4.22	1.44	12.93	5.83	19.76
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.90	59.41	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	100.00	66.51	99.97	99.94	99.85	98.75	98.42	99.09	99.31	20.10	38.12	94.97	95.78	98.56	87.07	94.17	80.24
12 MONTHS	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	19.03	19.03	21.90	20.04	11.45	6.47	6.30	6.21	6.20	6.20	4.06	3.84	3.83	3.57	0.54	1.41	1.90	3.60
MOR	3.33	3.33	3.21	2.88	2.54	2.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	5.15	5.15	6.16	5.51	4.86	3.62	2.90	1.79	1.41	1.35	1.35	1.62	1.68	1.80	1.16	1.39	1.41	1.59
PMOR	0.04	0.04	0.04	0.04	0.03	0.03	0.04	0.04	0.04	0.11	0.12	0.11	0.10	0.11	0.10	0.20	0.20	0.20
EUOR	25.32	25.32	28.59	26.22	17.67	11.92	9.06	7.93	7.56	7.57	5.47	5.50	5.54	5.41	1.80	2.98	3.47	5.32
EUOF	13.16	13.12	15.96	15.96	11.04	7.44	5.68	5.14	4.91	4.92	3.23	3.44	3.86	4.20	1.48	2.54	3.03	4.64
POF	27.65	25.93	17.47	9.28	5.74	5.74	5.74	5.74	5.74	5.74	12.02	11.59	11.59	11.62	11.62	11.62	11.62	11.62
EAF	59.19	60.94	66.57	74.76	83.22	86.82	88.58	89.12	89.35	89.34	84.75	84.97	84.55	84.18	86.90	85.84	85.35	83.74





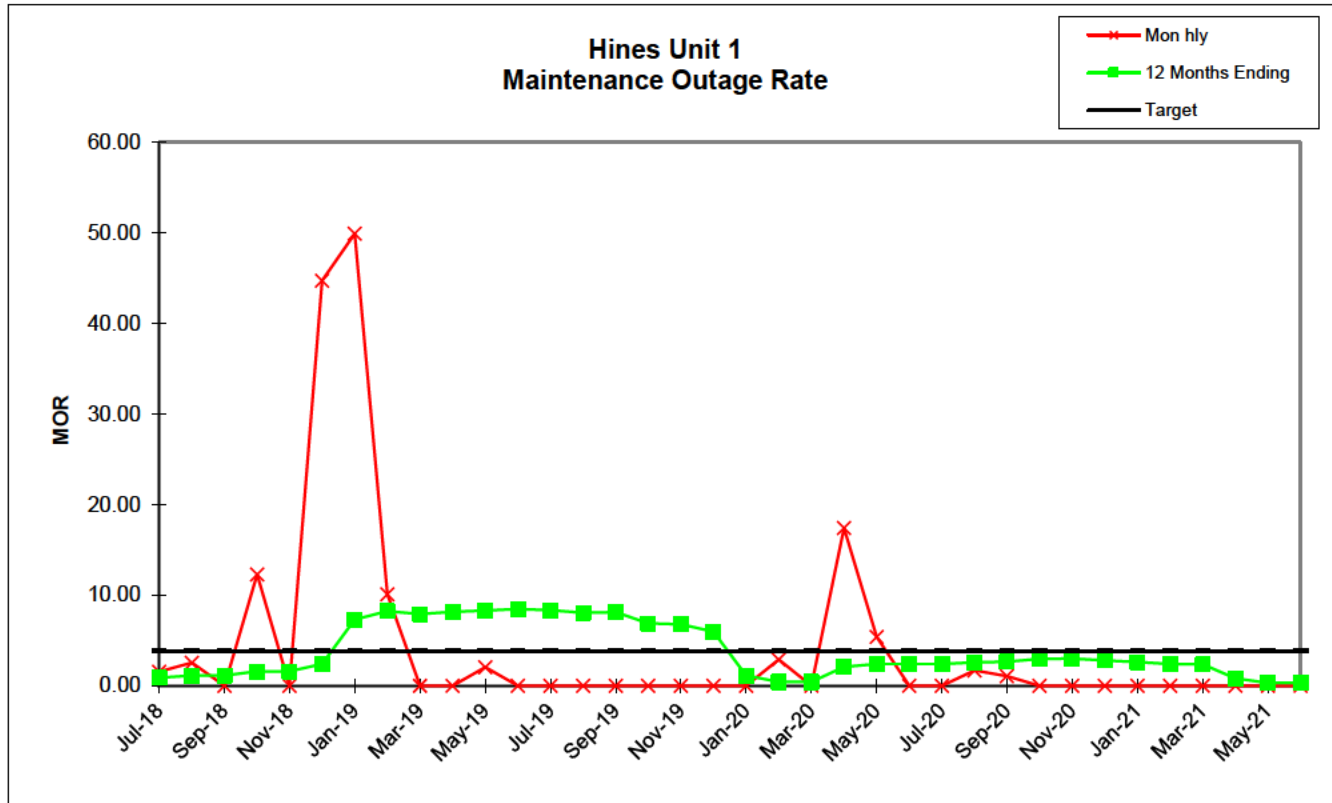
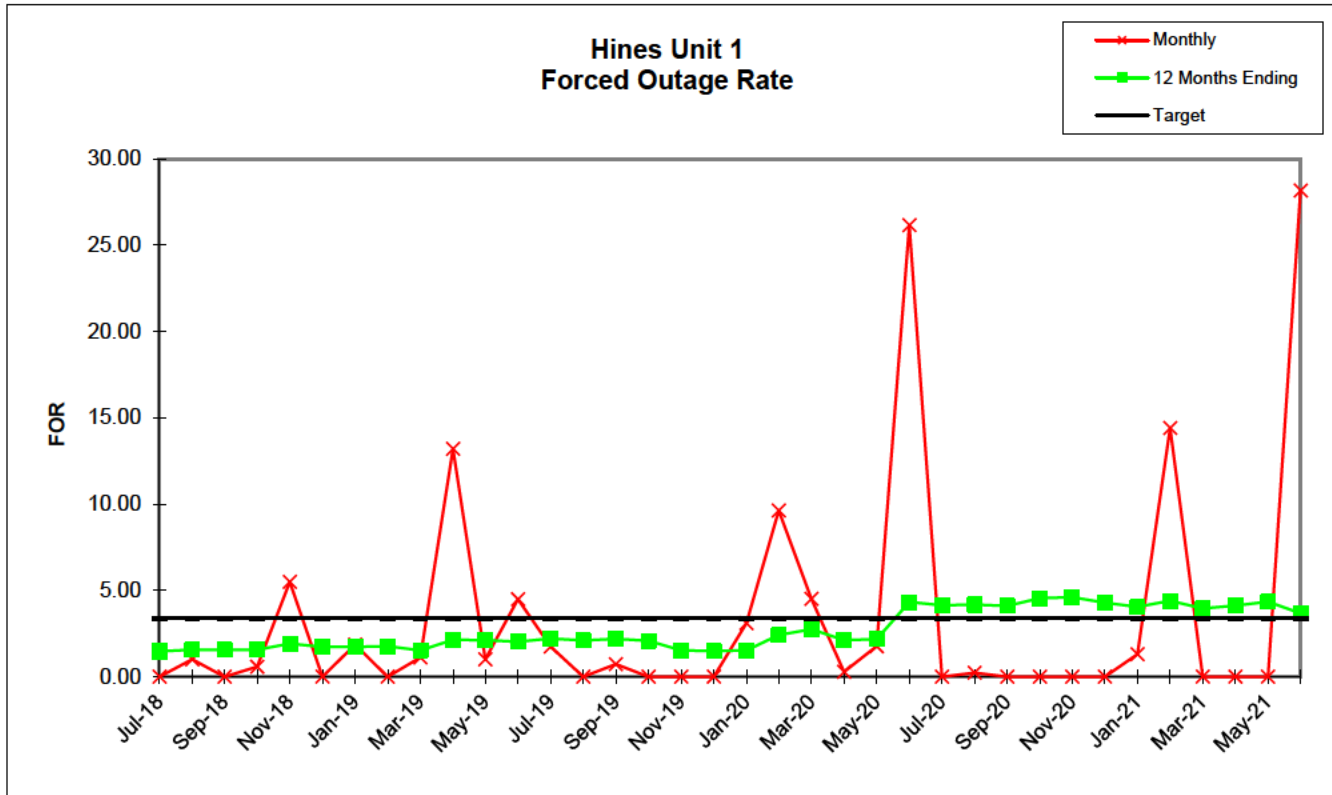


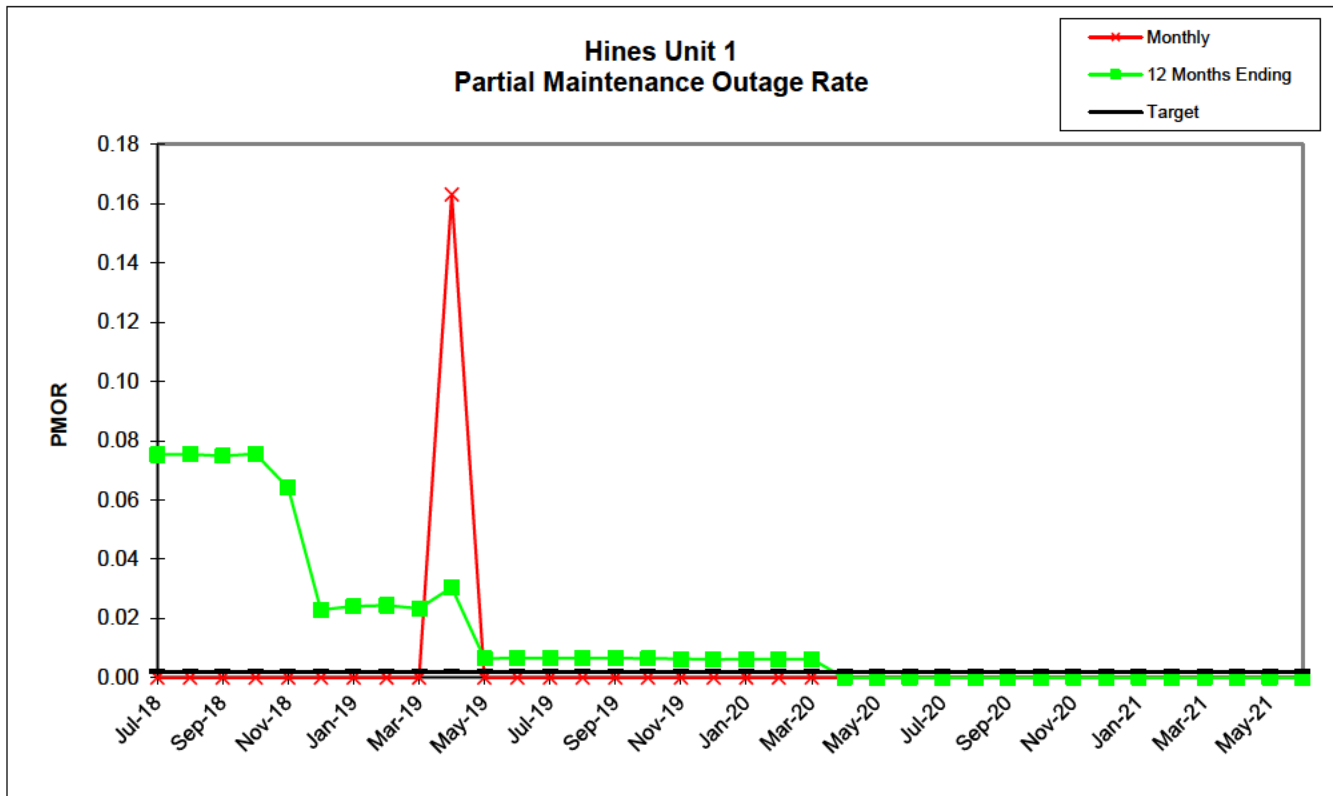
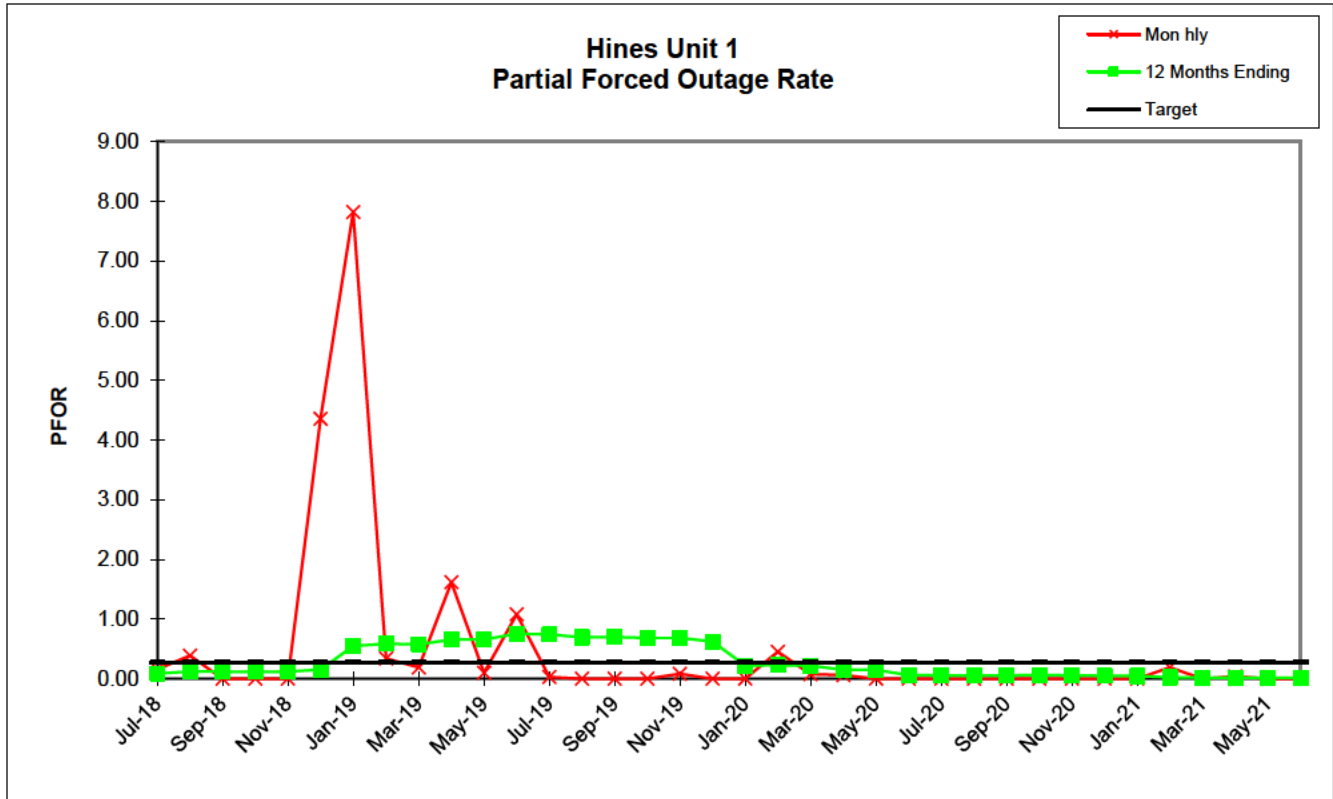
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Unit 1

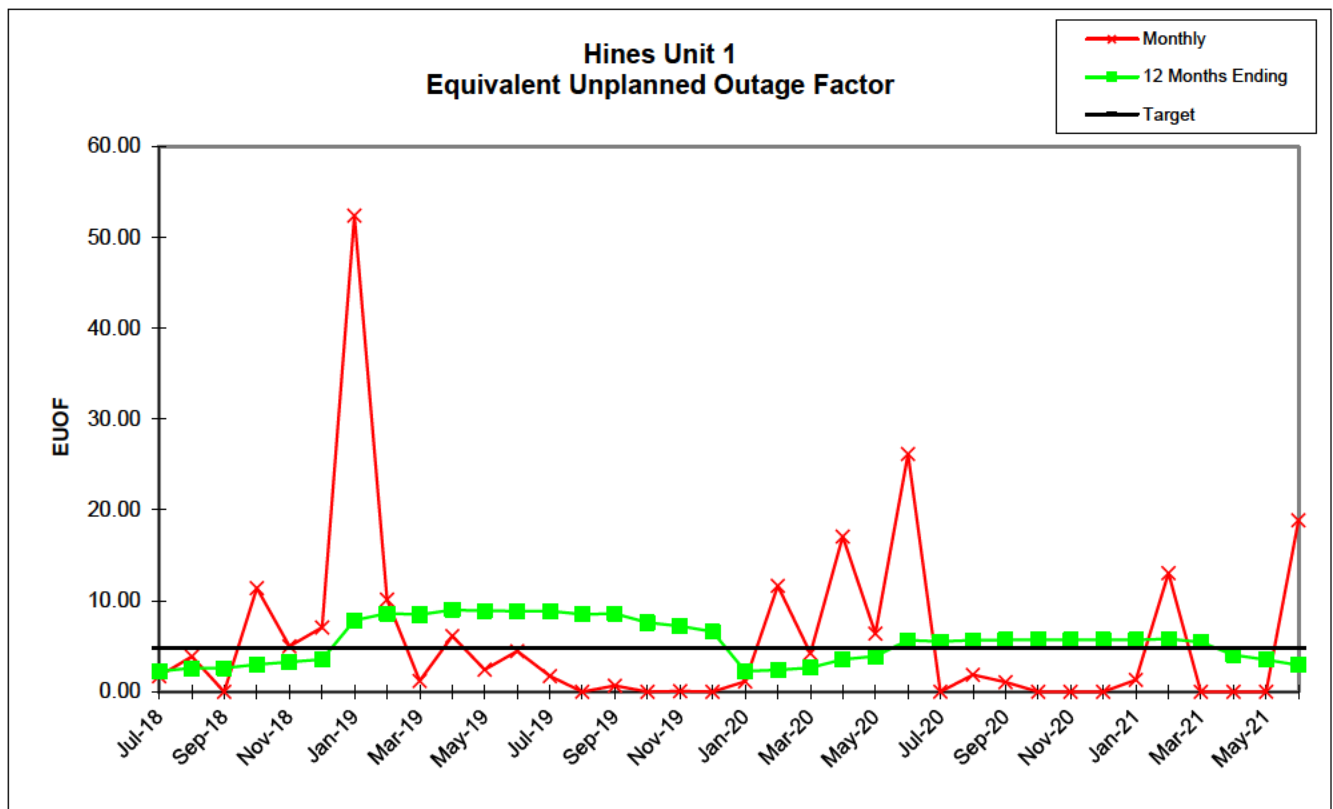
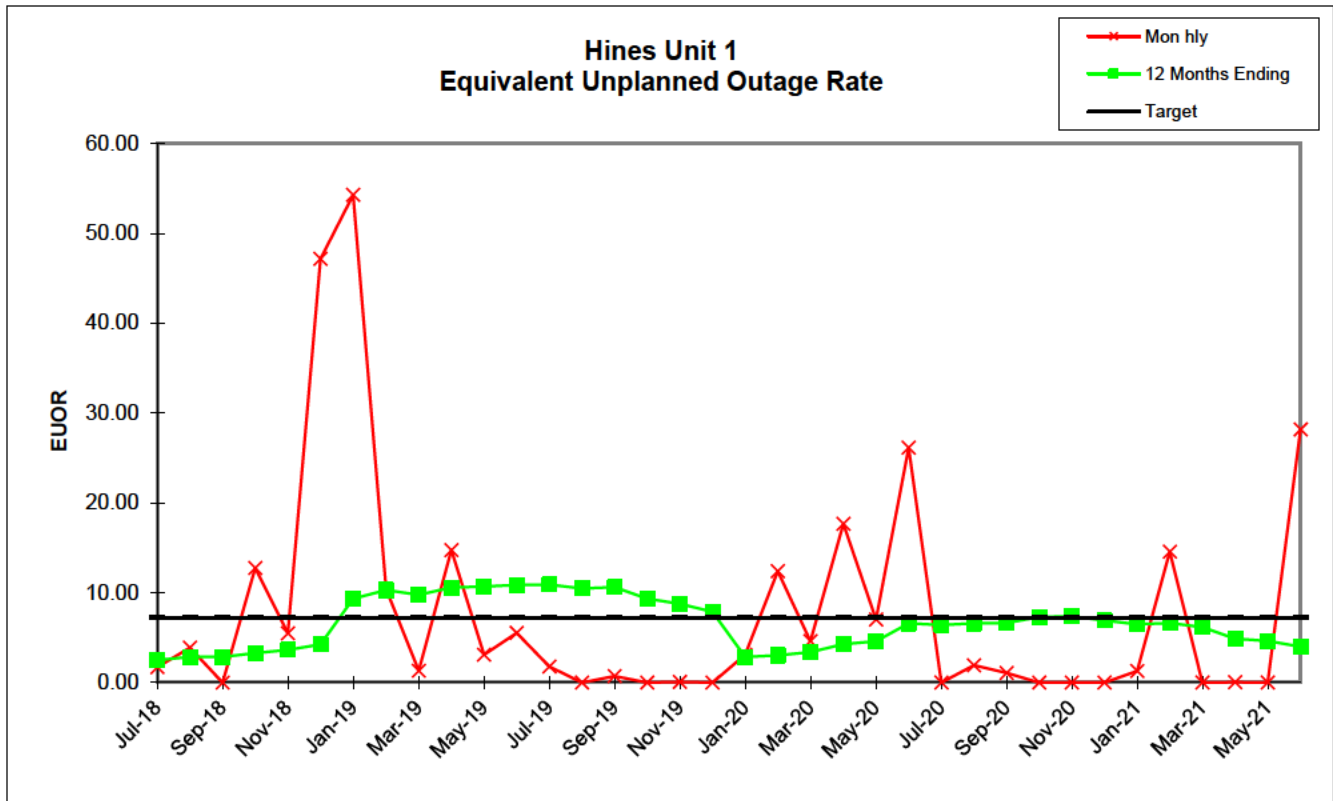
	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	732.31	715.07	720.00	580.80	621.72	61.63	356.18	588.34	669.00	259.95	562.87	555.81	705.57	744.00	676.25	726.62	721.00	264.97
RSH	0.00	2.76	0.00	78.31	63.08	632.44	25.73	17.44	66.37	28.53	5.00	138.05	25.81	0.00	38.81	17.38	0.00	479.03
UH	11.69	26.18	0.00	84.88	36.20	49.93	362.09	66.22	7.63	431.52	176.13	26.14	12.61	0.00	4.94	0.00	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	391.94	158.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	7.36	0.00	3.45	36.20	0.00	6.74	0.00	7.63	39.58	5.75	26.14	12.61	0.00	4.94	0.00	0.00	0.00
MOH	11.69	18.82	0.00	81.44	0.00	49.93	355.35	66.22	0.00	0.00	11.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	10.93	22.54	0.00	0.00	0.00	18.06	166.45	12.02	7.32	26.28	5.36	69.26	12.33	0.00	0.00	0.00	4.03	0.00
LRPF	51.62	61.35	0.00	0.00	0.00	73.61	82.00	82.02	85.08	78.36	51.29	42.41	8.00	0.00	0.00	0.00	74.52	0.00
EFOH	1.14	2.79	0.00	0.00	0.00	2.69	27.85	2.01	1.27	4.20	0.56	6.00	0.20	0.00	0.00	0.00	0.61	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	78.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	495.00	495.00	495.00	495.00	495.00	495.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00
MONTHLY	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	0.00	1.02	0.00	0.59	5.50	0.00	1.86	0.00	1.13	13.21	1.01	4.49	1.76	0.00	0.73	0.00	0.00	0.00
MOR	1.57	2.56	0.00	12.30	0.00	44.76	49.94	10.12	0.00	0.00	2.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.16	0.39	0.00	0.00	0.00	4.36	7.82	0.34	0.19	1.62	0.10	1.08	0.03	0.00	0.00	0.00	0.09	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	1.72	3.91	0.00	12.75	5.50	47.16	54.29	10.42	1.32	14.76	3.11	5.52	1.78	0.00	0.73	0.00	0.09	0.00
EUOF	1.72	3.89	0.00	11.41	5.02	7.07	52.41	10.15	1.20	6.14	2.43	4.46	1.72	0.00	0.69	0.00	0.09	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	54.44	21.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.28	96.11	100.00	88.59	94.98	92.93	47.59	89.85	98.80	39.42	76.25	95.54	98.28	100.00	99.31	100.00	99.91	100.00
12 MONTHS	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	1.47	1.57	1.56	1.57	1.91	1.74	1.74	1.76	1.52	2.14	2.11	2.03	2.22	2.10	2.19	2.09	1.54	1.49
MOR	0.90	1.14	1.13	1.59	1.61	2.41	7.32	8.25	7.92	8.17	8.33	8.48	8.36	8.08	8.13	6.89	6.80	5.97
PFOR	0.09	0.12	0.12	0.12	0.12	0.15	0.55	0.59	0.57	0.66	0.66	0.76	0.74	0.70	0.70	0.69	0.68	0.63
PMOR	0.08	0.08	0.07	0.08	0.06	0.02	0.02	0.02	0.02	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
EUOR	2.51	2.87	2.85	3.30	3.63	4.23	9.34	10.29	9.75	10.60	10.70	10.86	10.90	10.49	10.62	9.34	8.77	7.87
EUOF	2.26	2.59	2.59	2.99	3.27	3.56	7.84	8.62	8.50	9.00	8.91	8.87	8.87	8.54	8.60	7.63	7.22	6.62
POF	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	2.57	4.47	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
EAF	91.06	90.73	90.73	90.34	90.05	89.76	85.48	84.70	88.93	86.52	84.81	84.85	84.85	85.18	85.12	86.09	86.49	87.10

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Unit 1

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	259.00	575.22	654.59	573.34	632.06	531.58	744.00	710.18	688.92	3.58	647.01	744.00	734.33	515.04	743.00	238.92	0.00	346.32
RSH	476.68	42.26	57.41	24.00	64.25	0.00	0.00	19.83	23.58	48.00	0.00	0.00	0.00	70.21	0.00	0.00	0.00	22.67
UH	8.32	78.52	31.00	122.66	47.68	188.42	0.00	13.98	7.50	692.42	73.99	0.00	9.67	86.74	0.00	481.08	744.00	351.01
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	692.42	73.99	0.00	0.00	0.00	0.00	481.08	744.00	215.10
FOH	8.32	61.38	31.00	1.66	11.41	188.42	0.00	1.68	0.00	0.00	0.00	0.00	9.67	86.74	0.00	0.00	0.00	135.90
MOH	0.00	17.14	0.00	121.00	36.27	0.00	0.00	12.30	7.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	16.58	5.00	2.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.23	0.00	2.00	0.00	0.00
LRPF	0.00	77.00	49.54	82.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.98	0.00	23.91	0.00	0.00
EFOH	0.00	2.61	0.51	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.99	0.00	0.10	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00
MONTHLY	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	3.11	9.64	4.52	0.29	1.77	26.17	0.00	0.24	0.00	0.00	0.00	0.00	1.30	14.41	0.00	0.00	0.00	28.18
MOR	0.00	2.89	0.00	17.43	5.43	0.00	0.00	1.70	1.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.45	0.08	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.00	0.04	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	3.11	12.41	4.60	17.67	7.01	26.17	0.00	1.93	1.08	0.00	0.00	0.00	1.30	14.58	0.00	0.04	0.00	28.18
EUOF	1.12	11.66	4.24	17.08	6.41	26.17	0.00	1.88	1.04	0.00	0.00	0.00	1.30	13.06	0.00	0.01	0.00	18.88
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	93.07	10.26	0.00	0.00	0.00	0.00	66.82	100.00	29.88
EAF	98.88	88.34	95.76	82.92	93.59	73.83	100.00	98.12	98.96	6.93	89.74	100.00	98.70	86.94	100.00	33.17	0.00	51.25
12 MONTHS	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	1.54	2.42	2.75	2.12	2.17	4.33	4.14	4.19	4.11	4.56	4.61	4.30	4.05	4.40	3.96	4.12	4.35	3.69
MOR	1.14	0.43	0.43	2.09	2.40	2.41	2.40	2.57	2.67	2.96	3.00	2.79	2.61	2.41	2.38	0.80	0.31	0.32
PFOR	0.22	0.23	0.22	0.15	0.14	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.03	0.02	0.02	0.02	0.02
PMOR	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	2.87	3.05	3.38	4.27	4.61	6.59	6.40	6.60	6.63	7.32	7.39	6.91	6.50	6.63	6.17	4.87	4.65	4.00
EUOF	2.26	2.40	2.66	3.56	3.90	5.67	5.53	5.69	5.72	5.72	5.71	5.71	5.73	5.82	5.46	4.05	3.51	2.91
POF	6.29	6.27	6.27	1.81	0.00	0.00	0.00	0.00	0.00	7.88	8.73	8.73	8.73	8.75	8.75	14.24	22.73	25.19
EAF	91.45	91.33	91.07	94.64	96.10	94.33	94.47	94.31	94.28	86.40	85.57	85.57	85.55	85.43	85.79	81.71	73.76	71.90





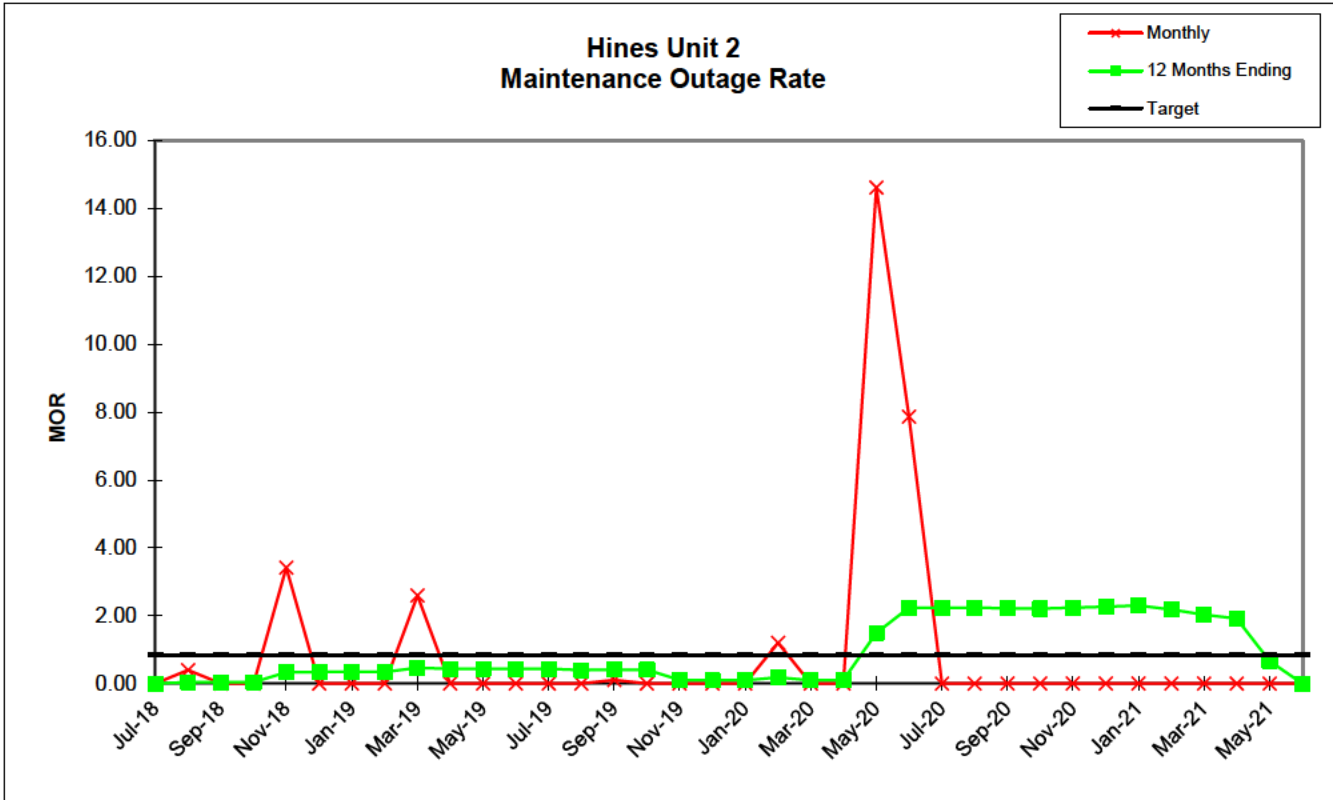
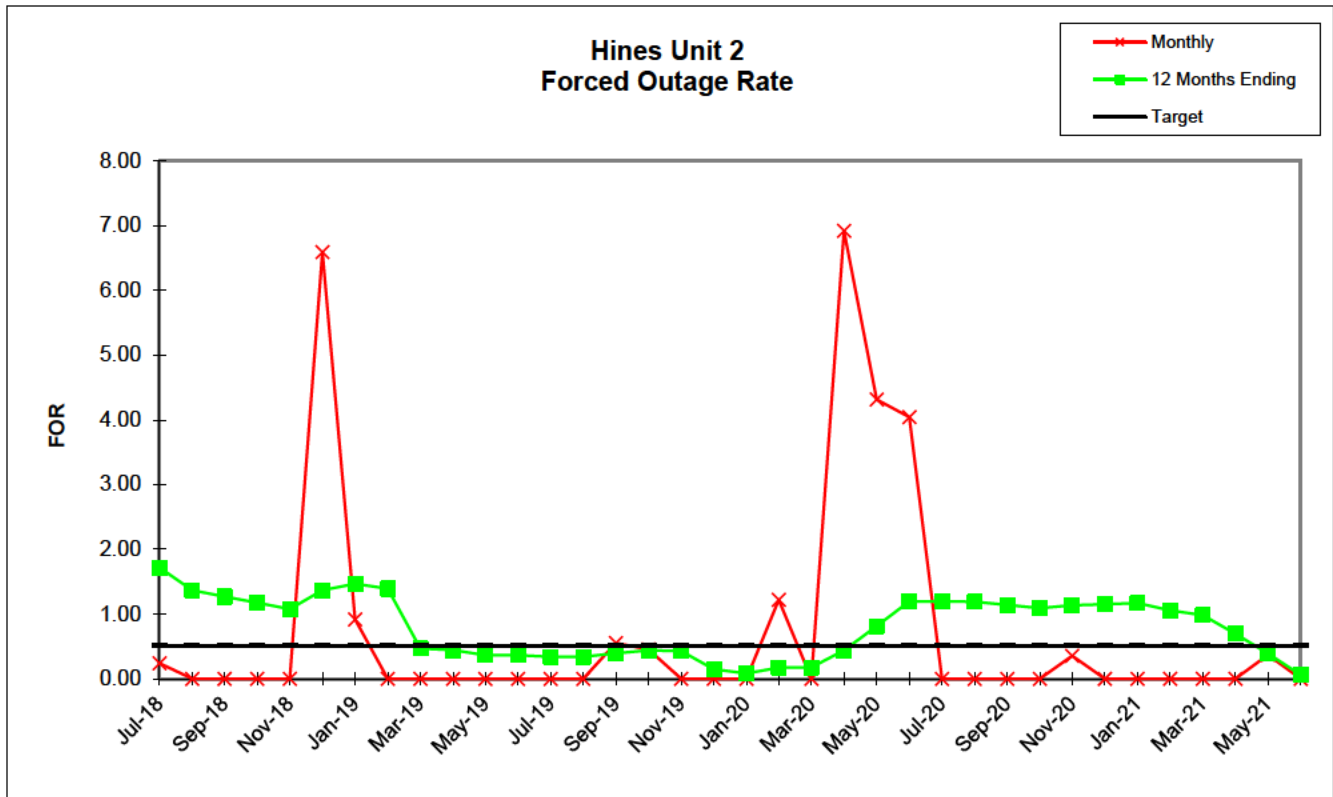


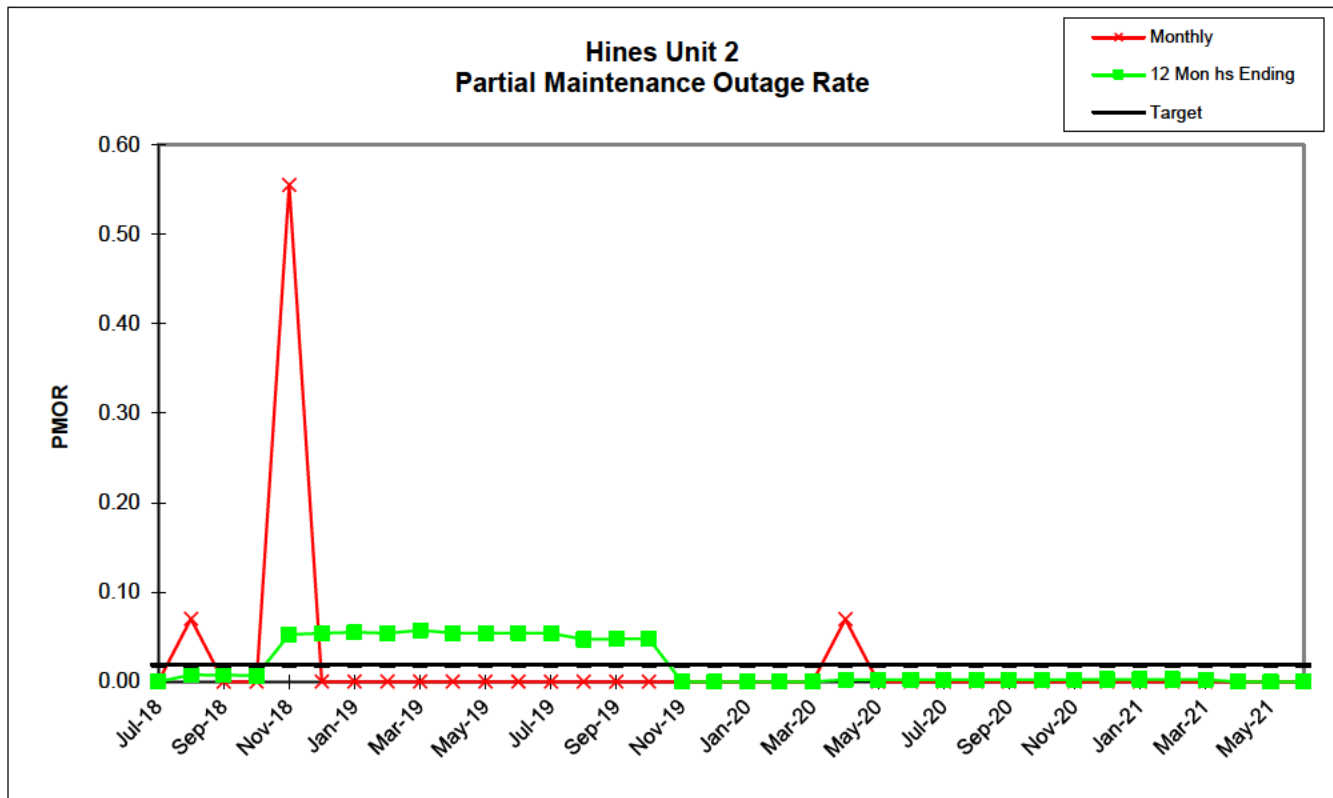
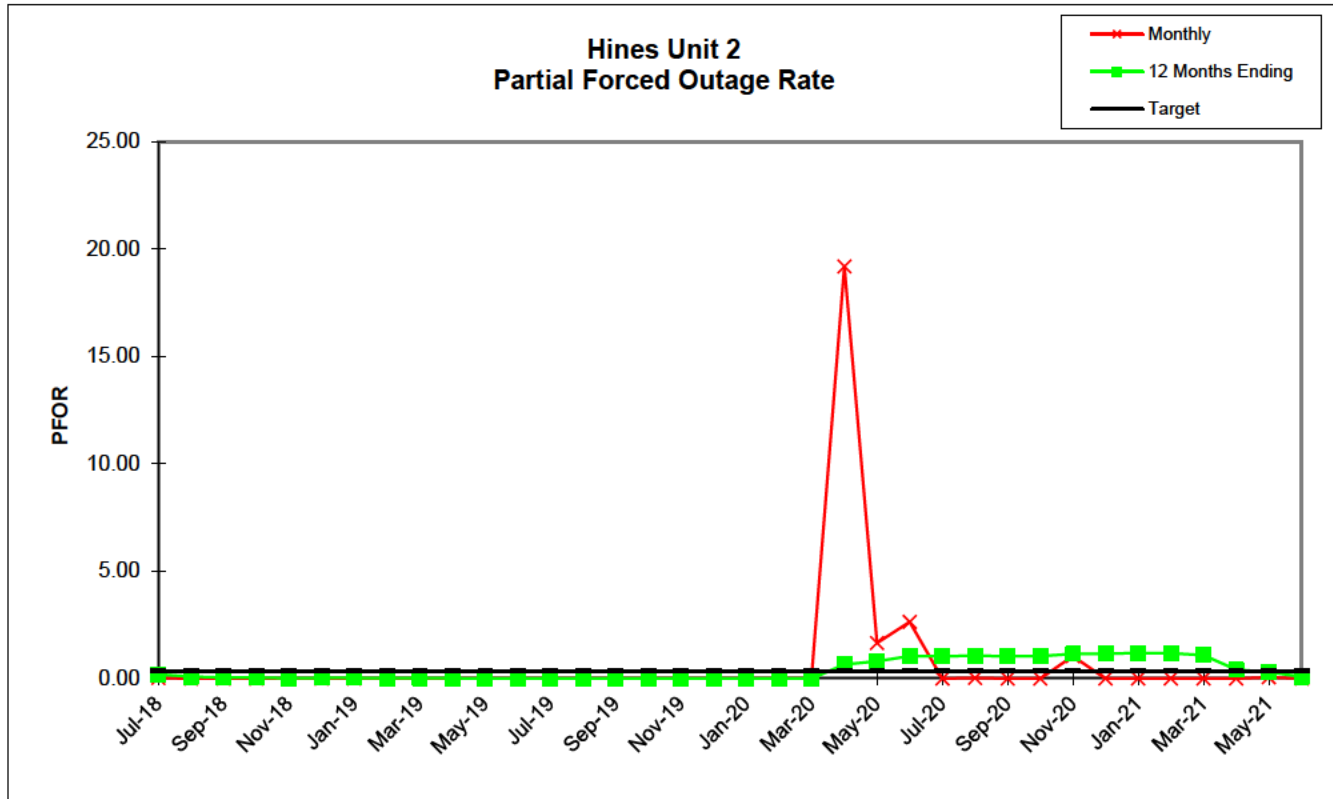
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Unit 2

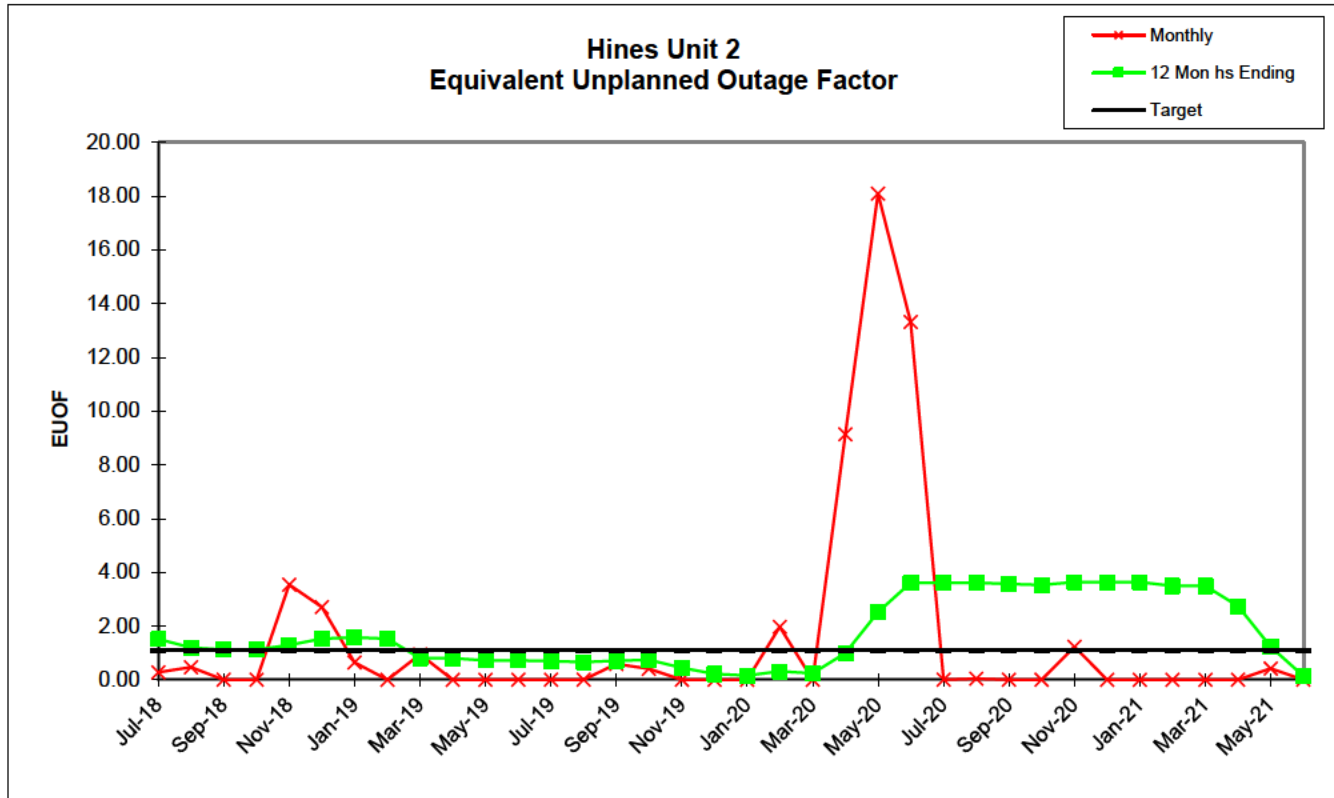
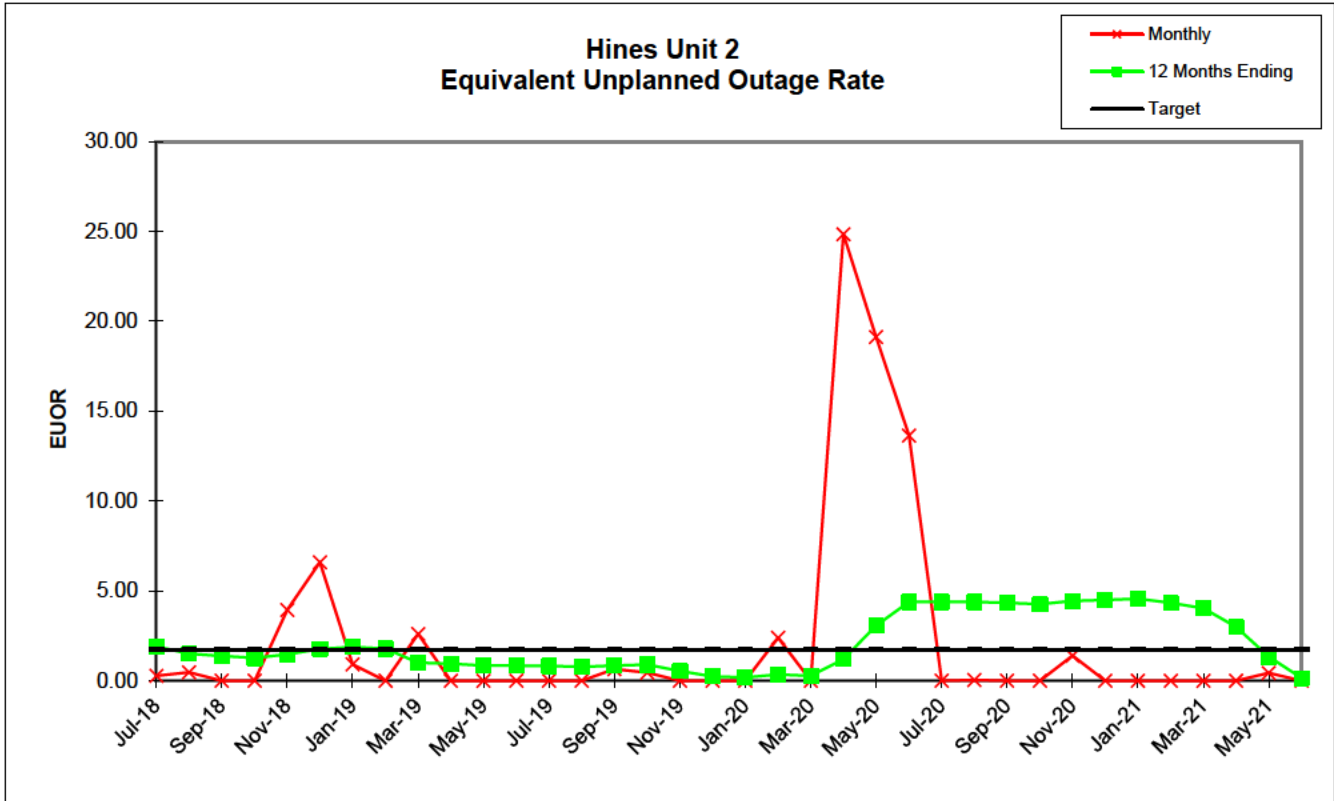
	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	742.21	741.04	720.00	712.89	625.29	285.04	522.14	594.16	262.42	703.77	741.59	693.36	743.00	738.04	651.29	669.50	721.00	744.00
RSH	0.00	0.00	0.00	31.11	73.62	438.84	217.02	77.84	142.29	16.23	2.41	26.64	1.00	5.96	64.44	71.44	0.00	0.00
UH	1.79	2.96	0.00	0.00	22.09	20.13	4.84	0.00	338.28	0.00	0.00	0.00	0.00	0.00	4.27	3.06	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	331.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	1.79	0.00	0.00	0.00	0.00	20.13	4.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.61	3.06	0.00	0.00
MOH	0.00	2.96	0.00	0.00	22.09	0.00	0.00	0.00	7.00	0.00	0.00	0.00	0.00	0.00	0.66	0.00	0.00	0.00
PFOH	1.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	86.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	2.91	0.00	0.00	22.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	94.40	0.00	0.00	80.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.52	0.00	0.00	3.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	527.00	527.00	527.00	527.00	527.00	527.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00
MONTHLY	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	0.24	0.00	0.00	0.00	0.00	6.60	0.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.55	0.45	0.00	0.00
MOR	0.00	0.40	0.00	0.00	3.41	0.00	0.00	0.00	2.60	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00
PFOR	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.07	0.00	0.00	0.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.28	0.47	0.00	0.00	3.95	6.60	0.92	0.00	2.60	0.00	0.00	0.00	0.00	0.00	0.65	0.45	0.00	0.00
EUOF	0.28	0.47	0.00	0.00	3.54	2.71	0.65	0.00	0.94	0.00	0.00	0.00	0.00	0.00	0.59	0.41	0.00	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.72	99.53	100.00	100.00	96.46	97.29	99.35	100.00	54.47	100.00	100.00	100.00	100.00	100.00	99.41	99.59	100.00	100.00
12 MONTHS	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	1.72	1.37	1.27	1.17	1.07	1.37	1.47	1.39	0.47	0.45	0.36	0.36	0.34	0.34	0.39	0.44	0.43	0.15
MOR	0.00	0.04	0.04	0.04	0.33	0.34	0.35	0.34	0.46	0.44	0.43	0.43	0.43	0.39	0.41	0.41	0.10	0.10
PFOR	0.19	0.09	0.06	0.05	0.03	0.03	0.03	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.01	0.01	0.01	0.05	0.05	0.06	0.05	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00	0.00
EUOR	1.91	1.50	1.37	1.27	1.47	1.78	1.88	1.80	1.00	0.95	0.85	0.85	0.82	0.78	0.84	0.89	0.53	0.25
EUOF	1.51	1.19	1.12	1.12	1.29	1.52	1.58	1.53	0.80	0.80	0.72	0.72	0.70	0.66	0.71	0.74	0.45	0.22
POF	12.96	12.96	10.74	5.03	5.03	5.03	5.03	5.03	8.81	4.17	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78
EAF	85.53	85.85	88.14	93.85	93.68	93.45	93.39	93.44	90.39	95.03	95.50	95.50	95.52	95.56	95.51	95.48	95.77	96.00

Hines
Unit 2

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	703.55	559.17	0.00	246.44	578.69	623.31	744.00	744.00	671.64	709.70	639.86	634.03	608.03	621.61	537.54	697.40	725.04	720.00
RSH	40.45	98.96	0.00	12.92	40.18	17.21	0.00	0.00	48.36	34.30	78.88	109.97	135.97	50.39	205.46	22.60	16.29	0.00
UH	0.00	37.87	743.00	460.64	125.13	79.48	0.00	0.00	0.00	0.00	2.26	0.00	0.00	0.00	0.00	0.00	2.67	0.00
POH	0.00	24.16	743.00	442.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	6.90	0.00	18.32	26.09	26.27	0.00	0.00	0.00	0.00	2.26	0.00	0.00	0.00	0.00	0.00	2.67	0.00
MOH	0.00	6.81	0.00	0.00	99.04	53.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	165.08	41.68	91.09	0.00	1.15	0.00	0.00	47.90	0.00	0.00	0.00	0.00	0.00	2.53	0.00
LRPF	0.00	0.00	0.00	150.15	120.10	94.72	0.00	137.07	0.00	0.00	72.75	0.00	0.00	0.00	0.00	0.00	94.40	0.00
EFOH	0.00	0.00	0.00	47.30	9.55	16.47	0.00	0.30	0.00	0.00	6.65	0.00	0.00	0.00	0.00	0.00	0.46	0.00
PMOH	0.00	0.00	0.00	1.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	65.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00	524.00
MONTHLY	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	0.00	1.22	0.00	6.92	4.31	4.04	0.00	0.00	0.00	0.00	0.35	0.00	0.00	0.00	0.00	0.00	0.37	0.00
MOR	0.00	1.20	0.00	0.00	14.61	7.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	19.19	1.65	2.64	0.00	0.04	0.00	0.00	1.04	0.00	0.00	0.00	0.00	0.00	0.06	0.00
PMOR	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.00	2.39	0.00	24.85	19.14	13.65	0.00	0.04	0.00	0.00	1.39	0.00	0.00	0.00	0.00	0.00	0.43	0.00
EUOF	0.00	1.97	0.00	9.14	18.10	13.33	0.00	0.04	0.00	0.00	1.24	0.00	0.00	0.00	0.00	0.00	0.42	0.00
POF	0.00	3.47	100.00	61.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	94.56	0.00	29.43	81.90	86.67	100.00	99.96	100.00	100.00	98.76	100.00	100.00	100.00	100.00	100.00	99.58	100.00
12 MONTHS	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	0.08	0.17	0.18	0.44	0.82	1.19	1.19	1.19	1.14	1.09	1.13	1.15	1.17	1.06	0.98	0.69	0.39	0.06
MOR	0.10	0.18	0.10	0.10	1.49	2.24	2.24	2.24	2.22	2.21	2.23	2.27	2.30	2.18	2.03	1.91	0.66	0.00
PFOR	0.00	0.00	0.00	0.66	0.81	1.05	1.05	1.05	1.04	1.15	1.17	1.19	1.19	1.18	1.09	0.42	0.30	0.09
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.18	0.35	0.27	1.20	3.07	4.40	4.40	4.40	4.33	4.26	4.43	4.50	4.56	4.34	4.03	2.99	1.35	0.15
EUOF	0.16	0.32	0.24	0.99	2.52	3.61	3.61	3.62	3.57	3.53	3.64	3.64	3.64	3.49	3.49	2.74	1.24	0.14
POF	3.78	4.05	8.73	13.77	13.77	13.77	13.77	13.77	13.77	13.77	13.77	13.77	13.77	13.53	5.05	0.00	0.00	0.00
EAF	96.05	95.63	91.03	85.24	83.71	82.62	82.62	82.61	82.66	82.70	82.60	82.60	82.60	82.98	91.46	97.26	98.76	99.86





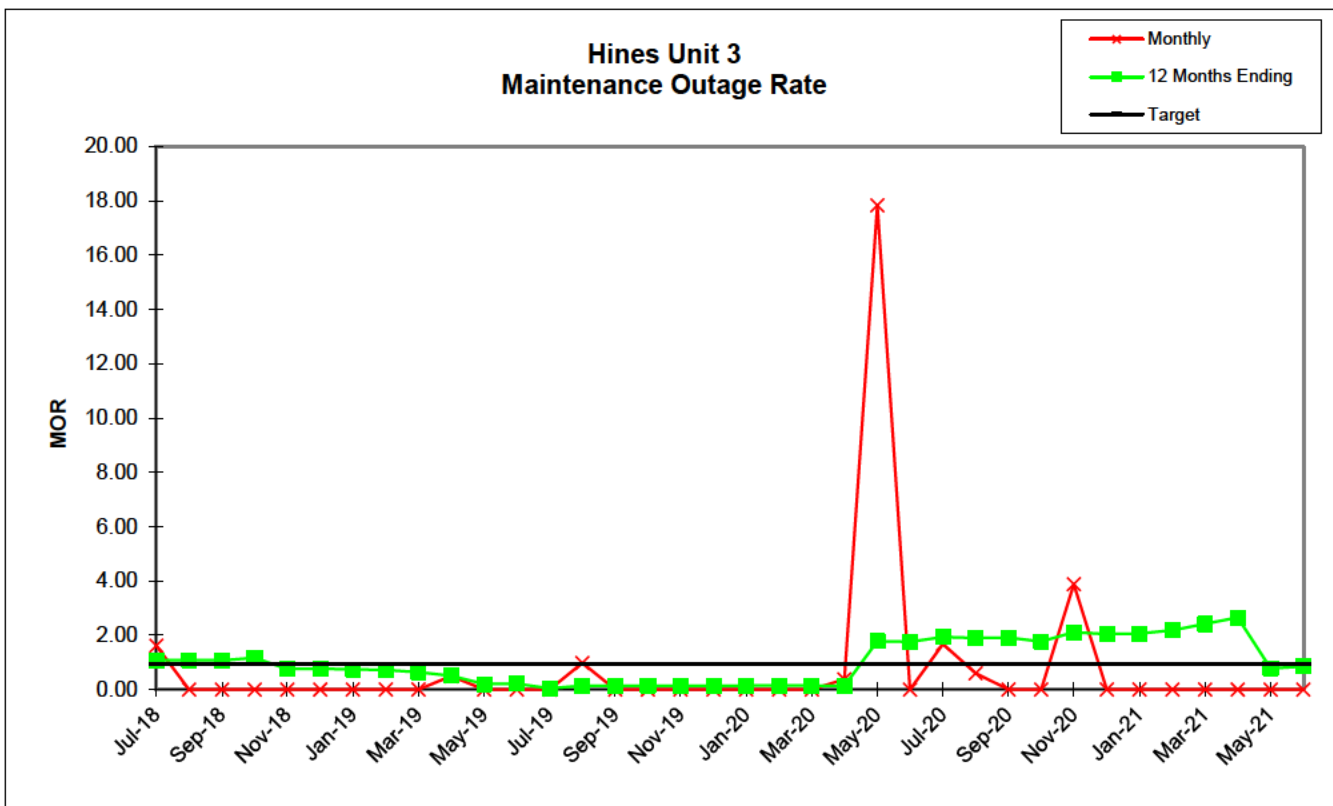
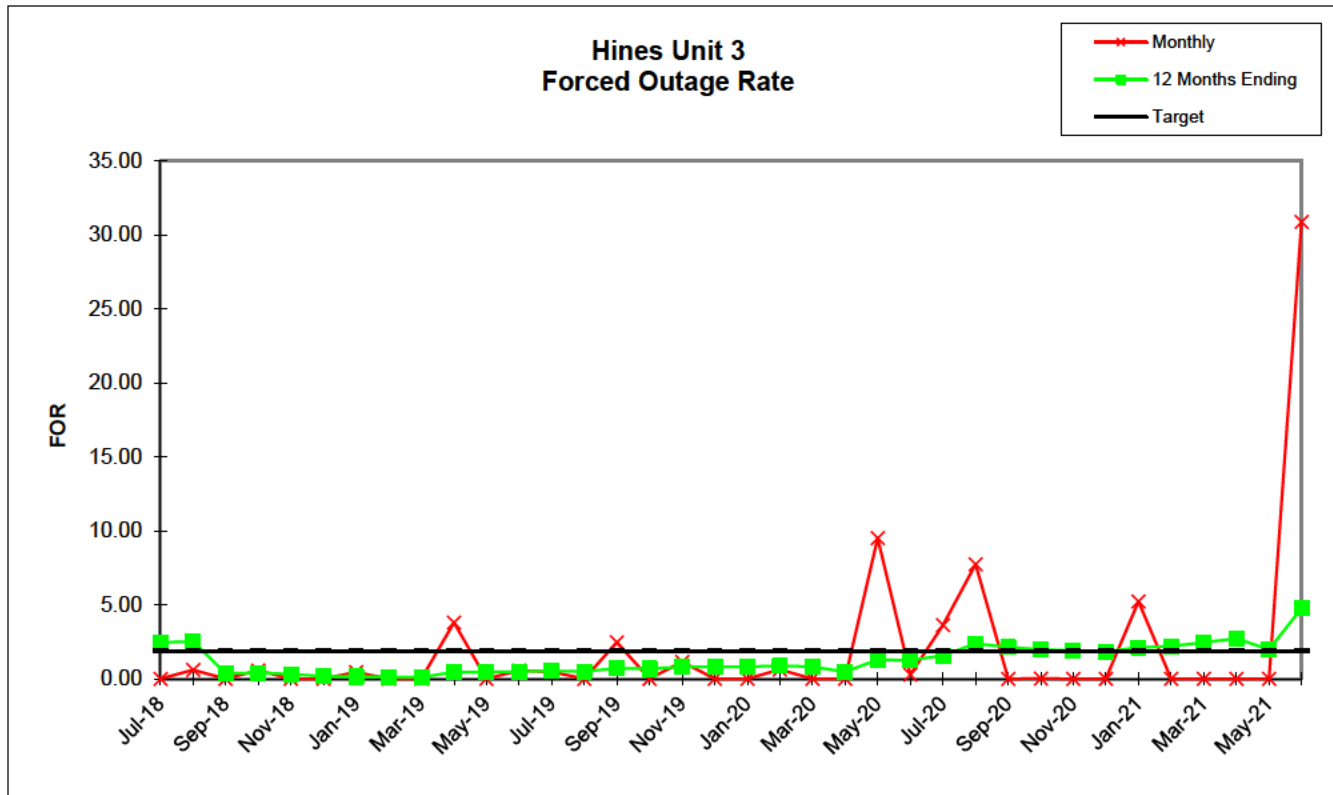


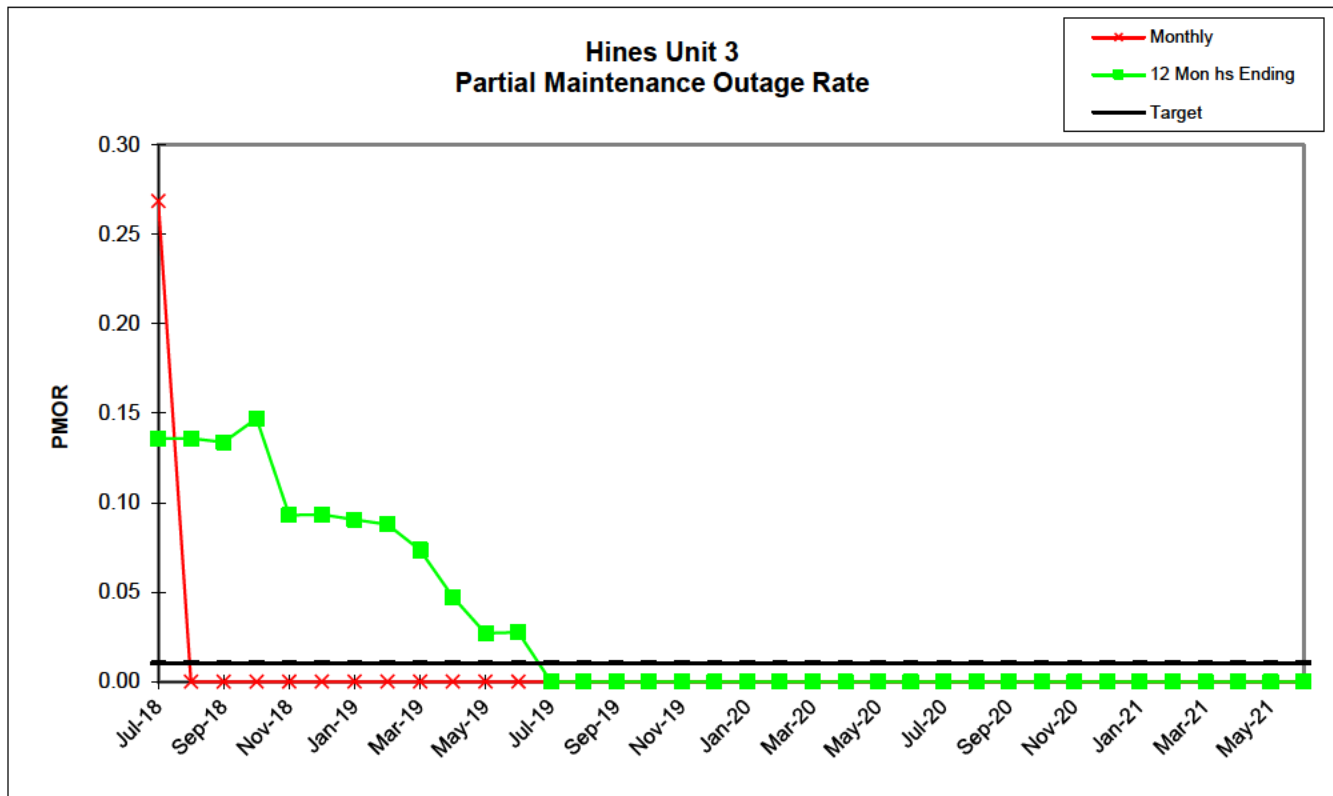
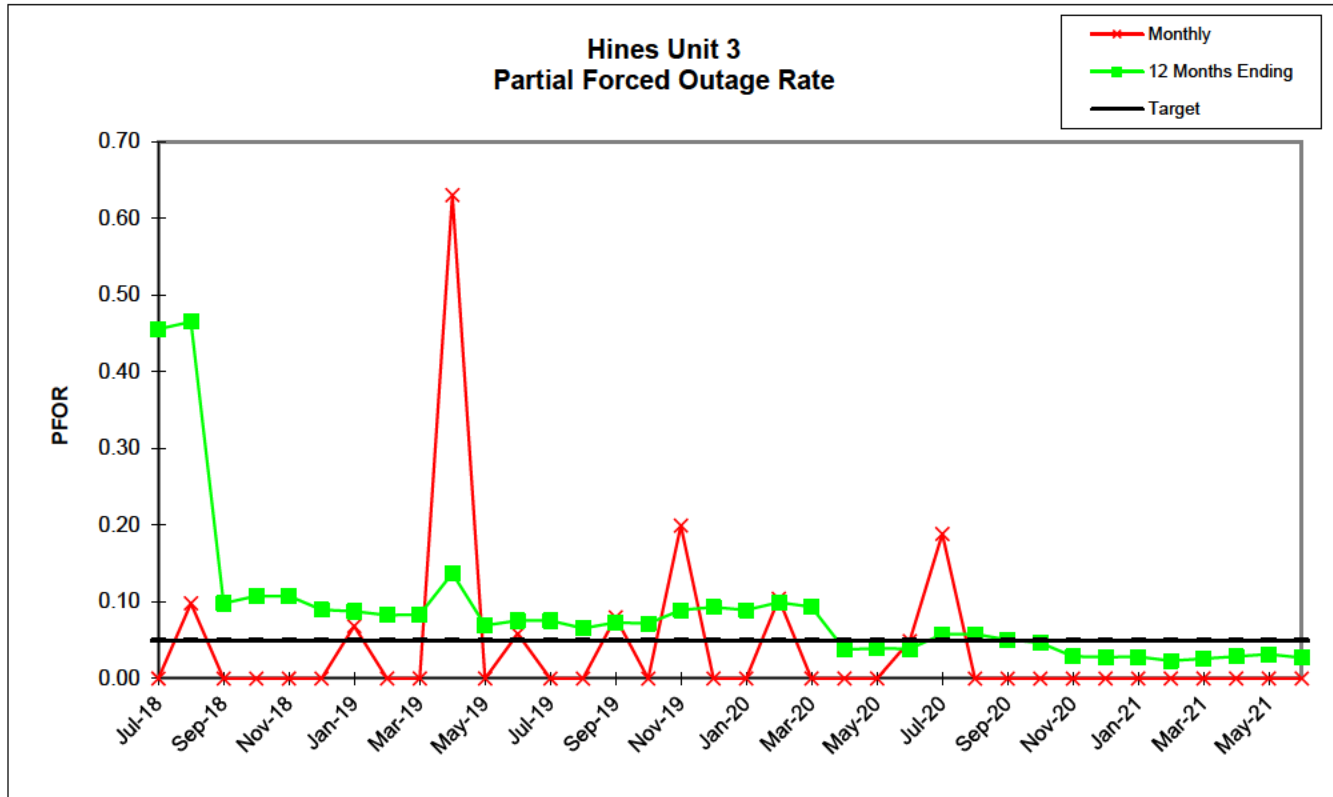
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Unit 3

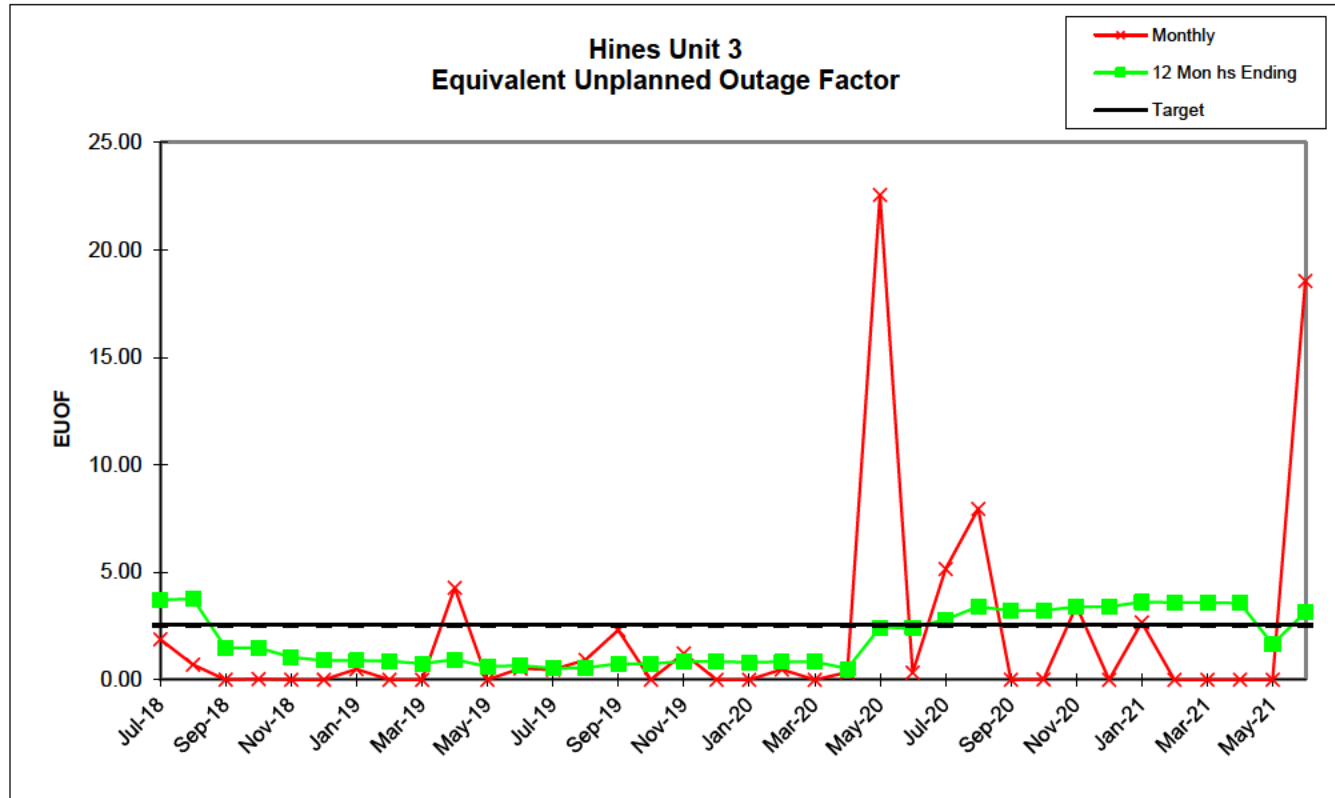
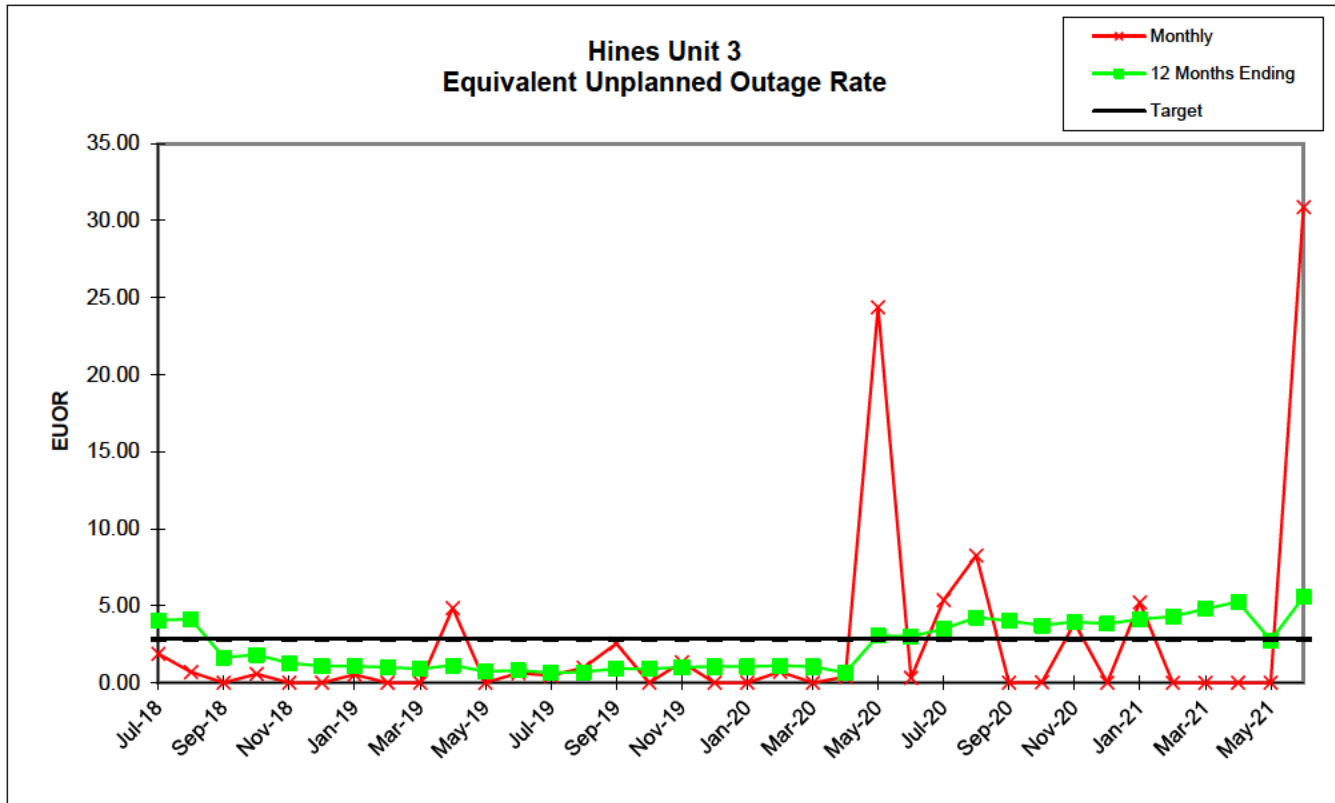
	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	731.95	739.49	673.52	39.01	605.99	706.70	700.11	638.34	343.61	606.56	744.00	604.15	726.72	702.23	640.48	190.87	658.48	395.39
RSH	0.00	0.00	0.00	0.00	113.58	37.30	40.69	33.66	399.39	86.52	0.00	112.43	13.86	34.81	63.38	0.00	54.95	348.61
UH	12.05	4.51	46.48	704.99	1.43	0.00	3.20	0.00	0.00	26.93	0.00	3.42	3.43	6.95	16.13	553.13	7.57	0.00
POH	0.00	0.00	46.48	704.77	1.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	553.13	0.00	0.00
FOH	0.00	4.51	0.00	0.22	0.00	0.00	3.20	0.00	0.00	23.93	0.00	3.42	3.43	0.00	16.13	0.00	7.57	0.00
MOH	12.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.00	0.00	0.00	6.95	0.01	0.00	0.00	0.00
PFOH	0.00	4.40	0.00	0.00	0.00	0.00	3.28	0.00	0.00	24.53	0.00	3.68	0.00	0.00	3.17	0.00	7.77	0.00
LRPF	0.00	86.01	0.00	0.00	0.00	0.00	75.32	0.00	0.00	80.41	0.00	49.58	0.00	0.00	83.25	0.00	87.28	0.00
EFOH	0.00	0.73	0.00	0.00	0.00	0.00	0.48	0.00	0.00	3.82	0.00	0.35	0.00	0.00	0.51	0.00	1.31	0.00
PMOH	11.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	87.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	1.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	521.00	521.00	521.00	521.00	521.00	521.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00
MONTHLY	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	0.00	0.61	0.00	0.56	0.00	0.00	0.45	0.00	0.00	3.80	0.00	0.56	0.47	0.00	2.46	0.00	1.14	0.00
MOR	1.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.49	0.00	0.00	0.00	0.98	0.00	0.00	0.00	0.00
PFOR	0.00	0.10	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.63	0.00	0.06	0.00	0.00	0.08	0.00	0.20	0.00
PMOR	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	1.88	0.70	0.00	0.56	0.00	0.00	0.52	0.00	0.00	4.85	0.00	0.62	0.47	0.98	2.54	0.00	1.33	0.00
EUOF	1.88	0.70	0.00	0.03	0.00	0.00	0.49	0.00	0.00	4.27	0.00	0.52	0.46	0.93	2.31	0.00	1.23	0.00
POF	0.00	0.00	6.46	94.73	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	74.35	0.00	0.00
EAF	98.12	99.30	93.54	5.24	99.80	100.00	99.51	100.00	100.00	95.73	100.00	99.48	99.54	99.07	97.69	25.65	98.77	100.00
12 MONTHS	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	2.46	2.51	0.35	0.39	0.32	0.15	0.15	0.12	0.11	0.44	0.44	0.49	0.54	0.48	0.71	0.69	0.79	0.82
MOR	1.09	1.09	1.07	1.17	0.76	0.76	0.74	0.72	0.63	0.51	0.21	0.21	0.04	0.14	0.14	0.14	0.14	0.14
PFOR	0.46	0.47	0.10	0.11	0.11	0.09	0.09	0.08	0.08	0.14	0.07	0.08	0.08	0.07	0.07	0.07	0.09	0.09
PMOR	0.14	0.14	0.13	0.15	0.09	0.09	0.09	0.09	0.07	0.05	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	4.06	4.13	1.64	1.81	1.27	1.10	1.07	1.00	0.90	1.13	0.74	0.80	0.66	0.68	0.92	0.90	1.01	1.06
EUOF	3.71	3.77	1.49	1.50	1.05	0.90	0.90	0.87	0.76	0.94	0.62	0.66	0.54	0.56	0.75	0.74	0.85	0.85
POF	0.00	0.00	0.53	8.58	8.59	8.59	8.59	8.59	8.59	8.59	8.59	8.59	8.59	8.59	8.06	6.33	6.31	6.31
EAF	96.29	96.23	97.98	89.93	90.36	90.51	90.51	90.53	90.65	90.47	90.79	90.75	90.87	90.85	91.19	92.92	92.84	92.84

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	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	460.05	460.19	726.67	655.96	521.00	714.93	678.16	657.55	633.63	725.20	612.82	652.41	360.54	68.63	0.00	0.00	0.00	299.01
RSH	283.95	232.97	16.33	61.54	55.10	3.06	28.76	27.24	86.37	18.65	83.48	91.59	363.58	219.37	0.00	0.00	0.00	0.00
UH	0.00	2.84	0.00	2.50	167.90	2.01	37.08	59.21	0.00	0.14	24.70	0.00	19.88	384.00	743.00	720.00	744.00	420.99
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	384.00	743.00	720.00	744.00	287.37
FOH	0.00	2.84	0.00	0.00	54.77	2.01	25.49	55.20	0.00	0.14	0.00	0.00	19.88	0.00	0.00	0.00	0.00	133.63
MOH	0.00	0.00	0.00	2.50	113.13	0.00	11.59	4.01	0.00	0.00	24.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	4.00	0.00	0.00	0.00	2.04	7.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	61.59	0.00	0.00	0.00	88.11	88.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.48	0.00	0.00	0.00	0.35	1.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	515.00	515.00	515.00	515.00	515.00	515.00	515.00	515.00	515.00	515.00	515.00	515.00	521.00	521.00	521.00	521.00	521.00	521.00
MONTHLY	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	0.00	0.61	0.00	0.00	9.51	0.28	3.62	7.74	0.00	0.02	0.00	0.00	5.23	0.00	0.00	0.00	0.00	30.89
MOR	0.00	0.00	0.00	0.38	17.84	0.00	1.68	0.61	0.00	0.00	3.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.10	0.00	0.00	0.00	0.05	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.00	0.72	0.00	0.38	24.37	0.33	5.36	8.26	0.00	0.02	3.87	0.00	5.23	0.00	0.00	0.00	0.00	30.89
EUOF	0.00	0.48	0.00	0.35	22.57	0.33	5.16	7.96	0.00	0.02	3.43	0.00	2.67	0.00	0.00	0.00	0.00	18.56
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.14	100.00	100.00	100.00	39.91
EAF	100.00	99.52	100.00	99.65	77.43	99.67	94.84	92.04	100.00	99.98	96.57	100.00	97.33	42.86	0.00	0.00	0.00	41.53
12 MONTHS	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	0.81	0.87	0.82	0.48	1.29	1.25	1.57	2.37	2.14	1.99	1.90	1.84	2.12	2.20	2.45	2.72	1.97	4.76
MOR	0.15	0.15	0.14	0.14	1.79	1.76	1.93	1.90	1.91	1.77	2.11	2.04	2.06	2.18	2.42	2.66	0.78	0.85
PFOR	0.09	0.10	0.09	0.04	0.04	0.04	0.06	0.06	0.05	0.05	0.03	0.03	0.03	0.02	0.03	0.03	0.03	0.03
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	1.04	1.12	1.06	0.65	3.07	3.00	3.50	4.24	4.02	3.74	3.96	3.83	4.13	4.30	4.78	5.27	2.76	5.56
EUOF	0.80	0.84	0.84	0.52	2.43	2.41	2.81	3.41	3.22	3.22	3.40	3.40	3.62	3.60	3.60	3.57	1.65	3.15
POF	6.31	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	0.00	0.00	0.00	0.00	4.38	12.87	21.08	29.58	32.86
EAF	92.88	92.86	92.86	93.18	91.27	91.29	90.89	90.30	90.49	96.78	96.60	96.60	96.38	92.02	83.54	75.35	68.77	63.99





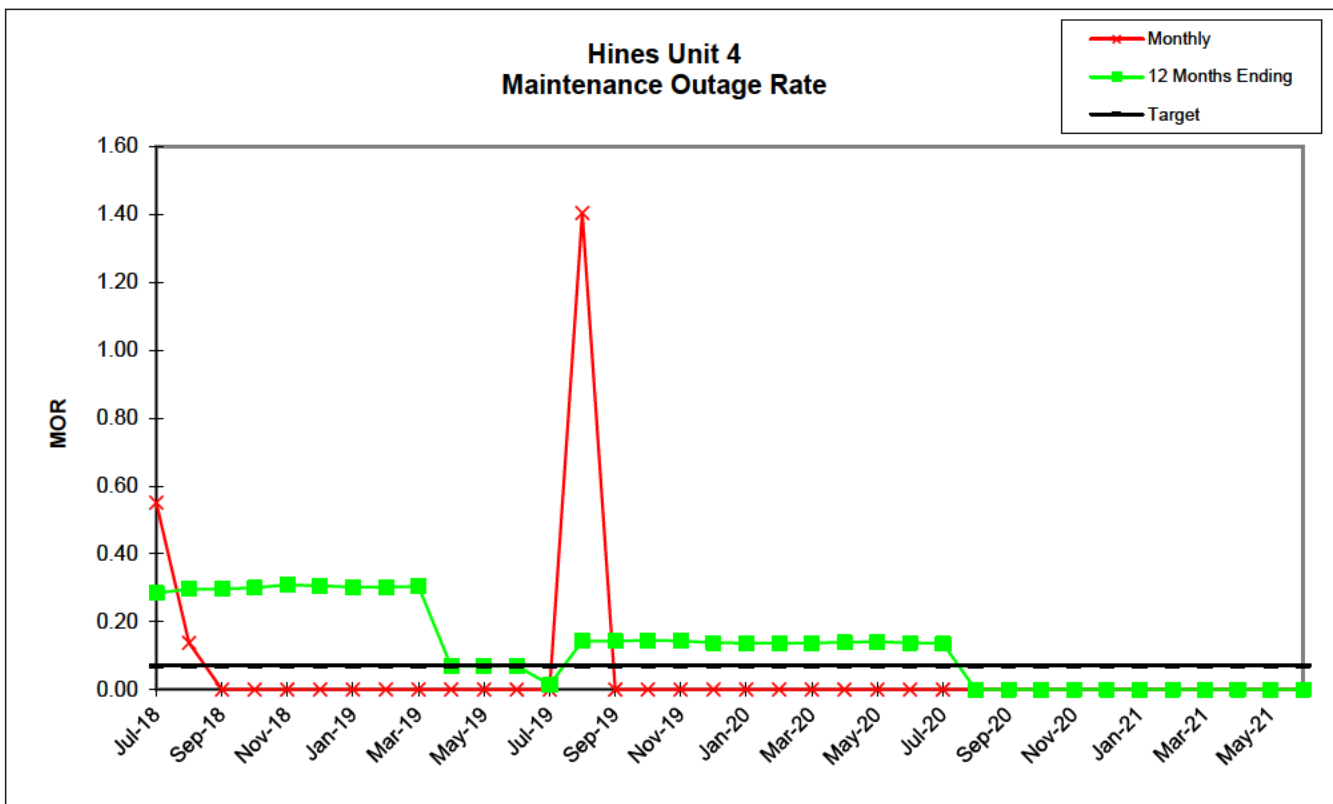
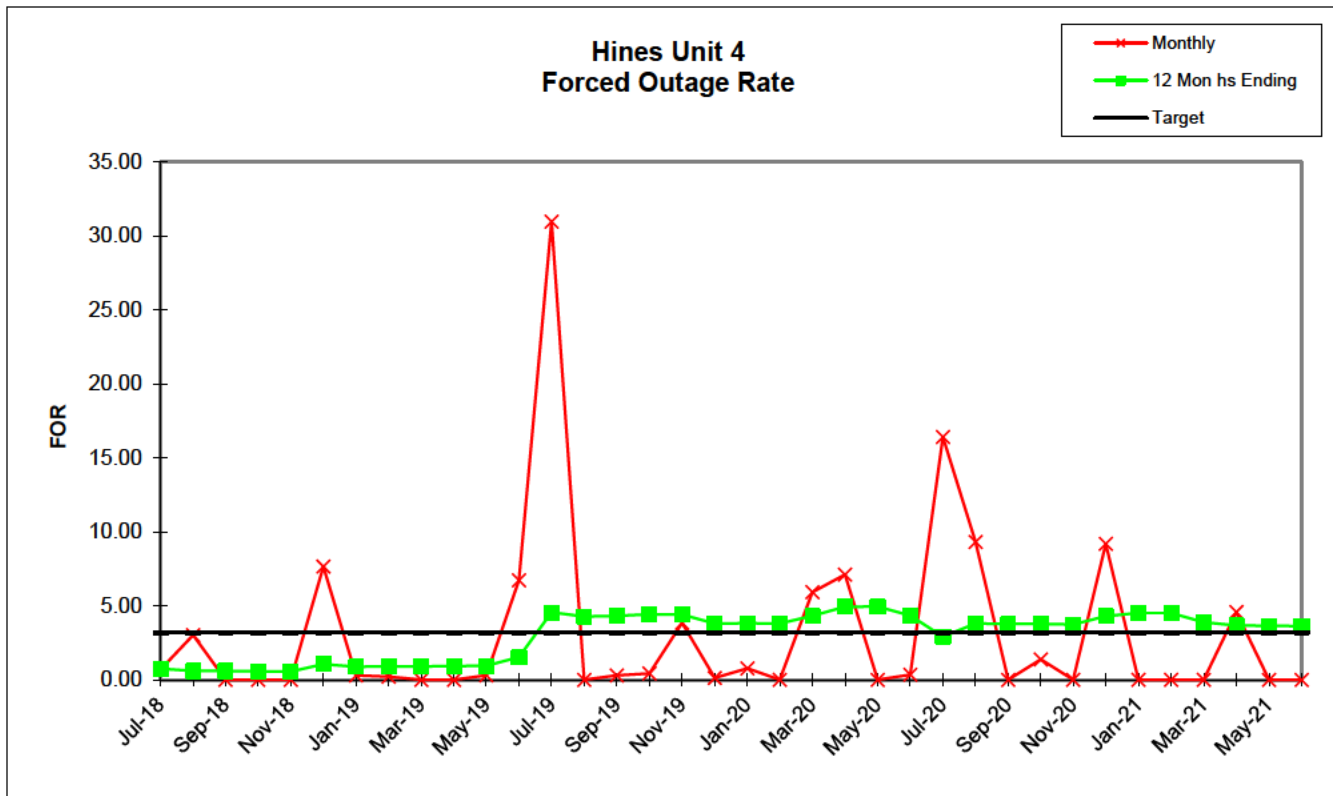


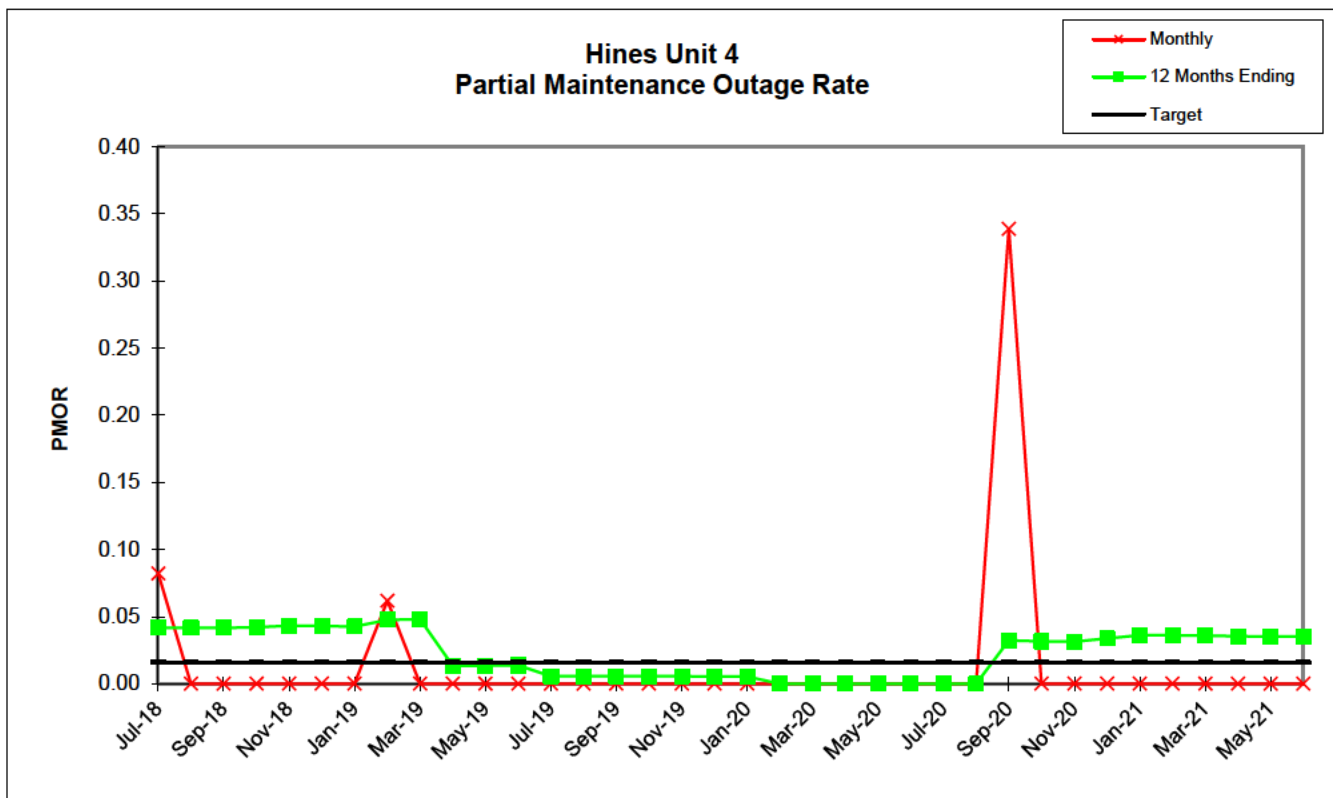
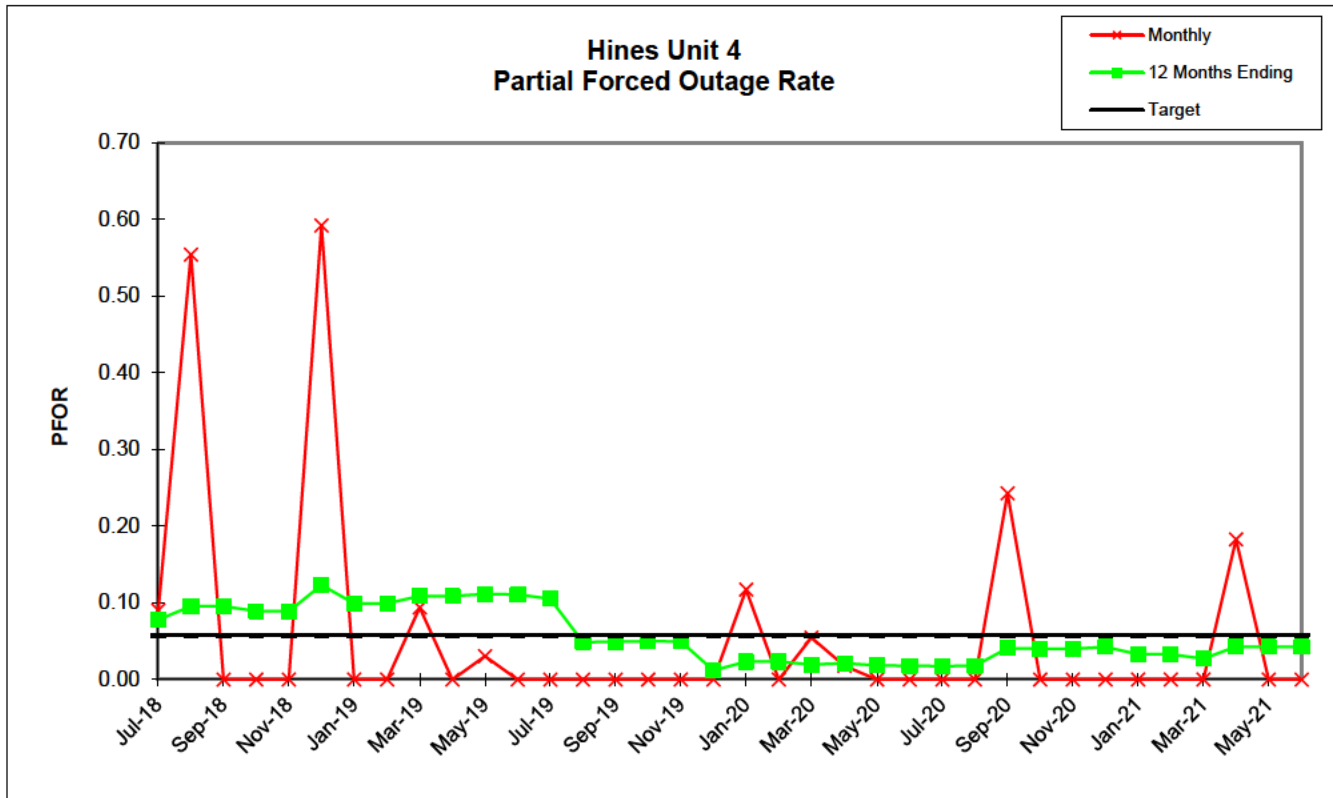
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Unit 4

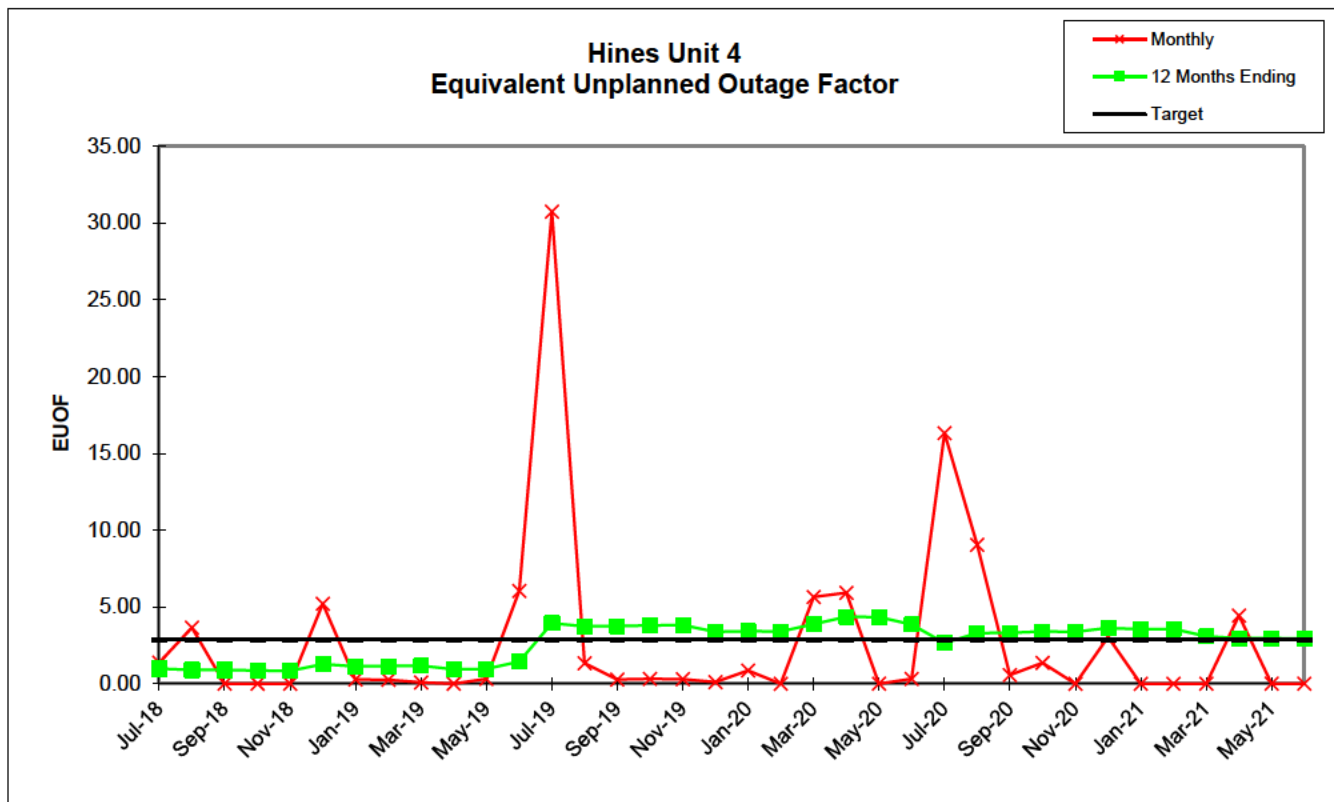
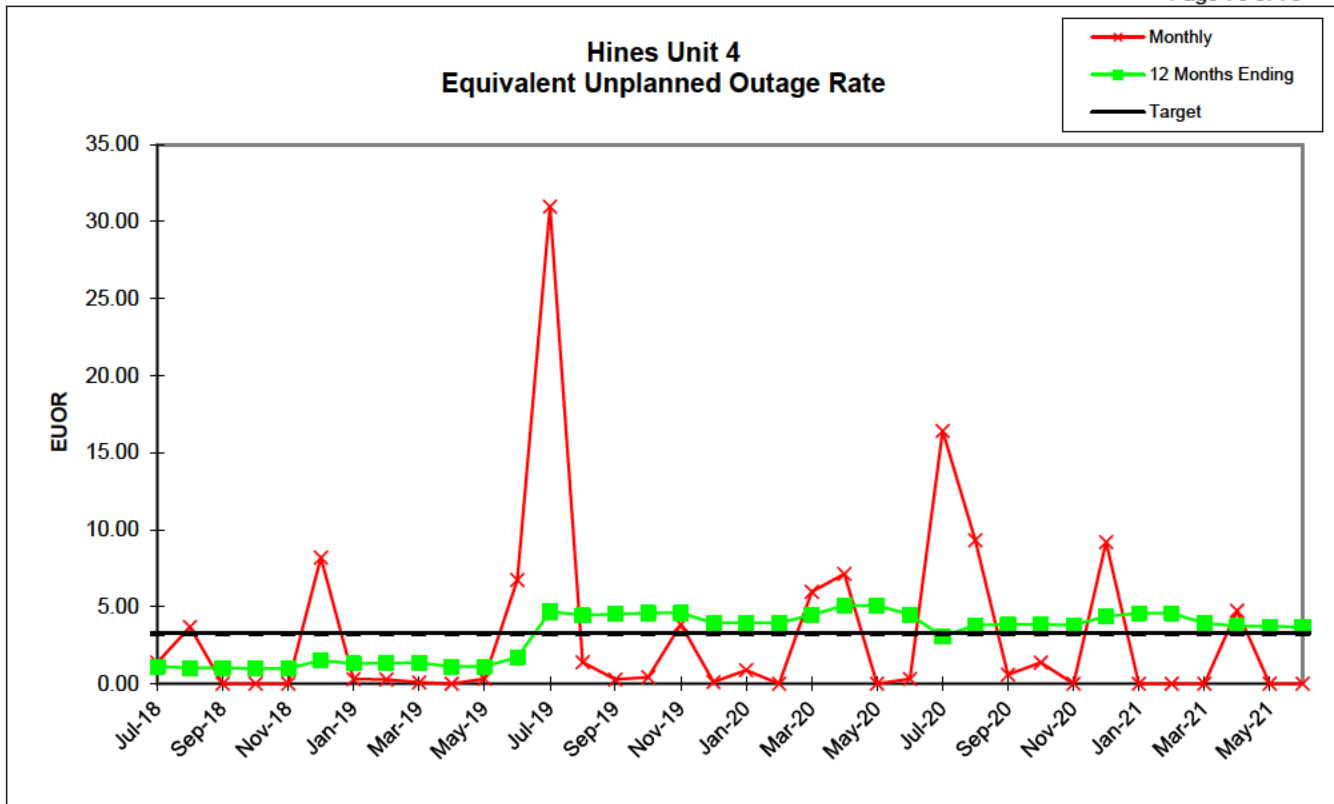
	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	734.94	715.29	720.00	640.18	0.00	436.62	677.19	637.21	680.19	678.23	738.92	603.62	509.75	702.35	685.27	542.99	53.31	734.79
RSH	0.00	5.44	0.00	103.82	328.02	76.72	64.80	33.43	62.81	41.77	2.89	72.83	5.43	31.65	32.76	55.83	0.00	1.49
UH	9.06	23.27	0.00	0.00	392.98	230.66	2.01	1.35	0.00	0.00	2.19	43.55	228.81	10.00	1.97	145.18	667.69	7.72
POH	0.00	0.00	0.00	0.00	392.98	194.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	142.82	665.56	6.91
FOH	4.99	22.28	0.00	0.00	0.00	36.20	2.01	1.35	0.00	0.00	2.19	43.55	228.81	0.00	1.97	2.36	2.13	0.81
MOH	4.07	0.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.00	0.00	0.00	0.00	0.00
PFOH	4.71	57.32	0.00	0.00	0.00	19.40	0.00	0.00	8.50	0.00	2.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	71.10	34.84	0.00	0.00	0.00	67.16	0.00	0.00	38.73	0.00	55.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.66	3.96	0.00	0.00	0.00	2.59	0.00	0.00	0.64	0.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	3.84	0.00	0.00	0.00	0.00	0.00	0.00	2.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	79.10	0.00	0.00	0.00	0.00	0.00	0.00	78.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	504.00	504.00	504.00	504.00	504.00	504.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00
MONTHLY	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	0.67	3.02	0.00	0.00	0.00	7.66	0.30	0.21	0.00	0.00	0.30	6.73	30.98	0.00	0.29	0.43	3.84	0.11
MOR	0.55	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	0.00	0.00	0.00	0.00
PFOR	0.09	0.55	0.00	0.00	0.00	0.59	0.00	0.00	0.09	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	1.39	3.69	0.00	0.00	0.00	8.20	0.30	0.27	0.09	0.00	0.33	6.73	30.98	1.40	0.29	0.43	3.84	0.11
EUOF	1.39	3.66	0.00	0.00	0.00	5.21	0.27	0.26	0.09	0.00	0.32	6.05	30.75	1.34	0.27	0.32	0.30	0.11
POF	0.00	0.00	0.00	0.00	54.50	26.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.20	92.31	0.93
EAF	98.61	96.34	100.00	100.00	45.50	68.65	99.73	99.74	99.91	100.00	99.68	93.95	69.25	98.66	99.73	80.49	7.39	98.96
12 MONTHS	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
FOR	0.74	0.59	0.59	0.56	0.56	1.04	0.88	0.90	0.91	0.91	0.94	1.53	4.56	4.28	4.33	4.42	4.41	3.79
MOR	0.28	0.30	0.30	0.30	0.31	0.31	0.30	0.30	0.30	0.07	0.07	0.07	0.01	0.14	0.14	0.14	0.14	0.14
PFOR	0.08	0.10	0.10	0.09	0.09	0.12	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.05	0.05	0.05	0.05	0.01
PMOR	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
EUOR	1.14	1.02	1.02	0.99	1.00	1.51	1.32	1.34	1.36	1.10	1.13	1.72	4.68	4.46	4.51	4.60	4.60	3.93
EUOF	1.00	0.89	0.89	0.85	0.84	1.28	1.14	1.16	1.17	0.94	0.96	1.45	3.94	3.74	3.77	3.79	3.82	3.38
POF	8.88	8.88	8.88	8.88	7.78	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	8.34	11.45	9.31
EAF	90.12	90.23	90.23	90.27	91.38	92.01	92.16	92.14	92.13	92.36	92.33	91.85	89.35	89.55	89.53	87.87	84.73	87.31

Hines
Unit 4

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	720.85	648.90	663.15	556.20	697.39	717.64	618.72	654.69	696.71	728.40	72.30	224.25	247.46	657.22	730.86	645.00	734.45	720.00
RSH	17.57	47.10	38.15	121.23	46.61	0.00	3.81	22.02	23.29	5.48	54.70	34.77	496.54	14.78	12.14	44.13	9.55	0.00
UH	5.58	0.00	41.70	42.57	0.00	2.36	121.47	67.29	0.00	10.11	594.00	484.98	0.00	0.00	0.00	30.87	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	594.00	462.31	0.00	0.00	0.00	0.00	0.00	0.00
FOH	5.58	0.00	41.70	42.57	0.00	2.36	121.47	67.29	0.00	10.11	0.00	22.67	0.00	0.00	0.00	30.87	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	5.58	0.00	3.00	0.58	0.00	0.00	0.00	0.00	14.08	0.00	0.00	0.00	0.00	0.00	0.00	7.70	0.00	0.00
LRPF	78.07	0.00	62.43	89.00	0.00	0.00	0.00	0.00	62.01	0.00	0.00	0.00	0.00	0.00	0.00	79.56	0.00	0.00
EFOH	0.84	0.00	0.36	0.10	0.00	0.00	0.00	0.00	1.69	0.00	0.00	0.00	0.00	0.00	0.00	1.18	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	87.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	519.00	519.00	519.00	519.00	519.00	519.00
MONTHLY	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	0.77	0.00	5.92	7.11	0.00	0.33	16.41	9.32	0.00	1.37	0.00	9.18	0.00	0.00	0.00	4.57	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.12	0.00	0.05	0.02	0.00	0.00	0.00	0.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.88	0.00	5.97	7.13	0.00	0.33	16.41	9.32	0.58	1.37	0.00	9.18	0.00	0.00	0.00	4.74	0.00	0.00
EUOF	0.86	0.00	5.66	5.93	0.00	0.33	16.33	9.04	0.56	1.36	0.00	3.05	0.00	0.00	0.00	4.45	0.00	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	82.39	62.14	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.14	100.00	94.34	94.07	100.00	99.67	83.67	90.96	99.44	98.64	17.61	34.81	100.00	100.00	100.00	95.55	100.00	100.00
12 MONTHS	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FOR	3.81	3.79	4.32	4.93	4.93	4.34	2.92	3.80	3.77	3.78	3.74	4.29	4.51	4.50	3.88	3.67	3.65	3.61
MOR	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.04	0.04	0.04
PMOR	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
EUOR	3.97	3.94	4.47	5.08	5.08	4.49	3.07	3.82	3.84	3.85	3.81	4.36	4.58	4.57	3.94	3.74	3.72	3.69
EUOF	3.43	3.41	3.88	4.36	4.34	3.87	2.64	3.30	3.32	3.41	3.38	3.63	3.56	3.57	3.09	2.97	2.97	2.94
POF	9.31	9.28	9.28	9.28	9.28	9.28	9.28	9.28	9.28	7.66	6.84	12.03	12.03	12.06	12.06	12.06	12.06	12.06
EAF	87.26	87.31	86.84	86.36	86.38	86.85	88.07	87.42	87.40	88.94	89.78	84.34	84.41	84.37	84.85	84.97	84.97	85.00







FLORIDA POWER & LIGHT COMPANY
CALCULATION OF NET TRUE-UP

SCHEDULE: E1-A

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	E1-A True-Up Summary	Total
1	End of Period True-Up ⁽¹⁾	(\$41,940,023)
2		
3	Less - Actual Estimated True-up for the same period ⁽²⁾	\$30,951,780
4		
5	Net True-up for the period	<u>(\$72,891,803)</u>
6		
7	⁽¹⁾ Page 2, Column 16, Lines 42 & 43.	
8	⁽²⁾ Approved in FPSC Final Order PSC-2020-0439-FOF-EI	
9		
10	() Reflects under-recovery	
11		
12	Totals may not add due to rounding	

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	True-up	True Up Line	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	a-Jul - 2020	a-Aug - 2020	a-Sep - 2020	a-Oct - 2020	a-Nov - 2020	a-Dec - 2020	a-2020
1	Fuel Costs & Net Power Transactions	Fuel Cost of System Net Generation ⁽¹⁾	\$185,496,269	\$173,597,002	\$181,513,695	\$178,633,359	\$202,547,418	\$214,594,794	\$212,470,912	\$252,549,223	\$250,364,172	\$238,568,218	\$235,030,079	\$211,444,543	\$2,536,809,683
2		Fuel Cost of Stratified Sales	(\$2,094,059)	(\$2,259,573)	(\$2,232,617)	(\$2,381,561)	(\$2,073,042)	(\$2,254,470)	(\$2,521,290)	(\$3,062,108)	(\$3,524,034)	(\$2,951,401)	(\$2,986,022)	(\$2,450,366)	(\$30,790,542)
3		Rail Car Lease (Cedar Bay/CL/SJRPP)	\$150,371	\$167,770	\$159,866	\$226,043	\$219,296	\$215,927	\$154,501	\$162,785	\$178,081	\$150,616	\$197,596	\$158,994	\$2,141,847
4		Fuel Cost of Power Sold (Per A6)	(\$7,779,369)	(\$8,036,378)	(\$2,876,822)	(\$3,309,957)	(\$3,983,636)	(\$2,767,692)	(\$2,846,743)	(\$2,926,155)	(\$2,706,508)	(\$2,749,166)	(\$3,450,467)	(\$3,012,007)	(\$46,444,900)
5		Gains from Off-System Sales (Per A6)	(\$4,426,727)	(\$4,399,207)	(\$1,491,017)	(\$1,603,758)	(\$2,441,847)	(\$1,556,051)	(\$1,642,811)	(\$1,582,831)	(\$1,488,456)	(\$1,503,948)	(\$1,881,852)	(\$1,536,549)	(\$25,555,054)
6		Fuel Cost of Purchased Power (Per A7)	\$2,427,756	\$2,257,414	\$2,165,181	\$2,433,560	\$2,007,734	\$1,781,047	\$2,639,431	\$2,716,008	\$2,394,171	\$2,609,377	\$2,420,199	\$2,454,603	\$28,306,481
7		Energy Payments to Qualifying Facilities (Per A8)	\$321,716	\$405,060	\$339,253	\$362,152	\$340,189	\$280,482	\$300,852	\$316,285	\$331,445	\$381,238	\$349,409	\$373,840	\$4,101,922
8		Energy Cost of Economy Purchases (Per A9)	\$14,565	\$1,350	\$1,087,136	\$572,748	\$9,950	\$1,526,812	\$1,841,974	\$515,474	\$1,317,353	\$2,761,191	\$75,536	\$1,840	\$9,725,529
9		Total Fuel Costs & Net Power Transactions	\$174,110,520	\$161,733,439	\$178,664,676	\$174,932,586	\$196,626,063	\$211,820,849	\$210,396,826	\$248,688,683	\$246,866,224	\$237,266,125	\$229,754,478	\$207,434,898	\$2,478,295,367
10		Scherer Coal Cars Depreciation & Return													
11															
12	Incremental Optimization Costs	Incremental Personnel, Software, and Hardware Costs	\$46,772	\$43,406	\$46,420	\$45,450	\$43,986	\$46,732	\$42,515	\$37,656	\$39,292	\$41,653	\$37,427	\$41,016	\$512,326
13		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	\$295,617	\$320,119	\$121,837	\$142,065	\$169,117	\$112,095	\$112,295	\$109,423	\$103,827	\$104,163	\$130,554	\$106,196	\$1,827,307
14		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	(\$624)	(\$59)	(\$22,571)	(\$12,859)	(\$1,347)	(\$12,003)	(\$32,983)	(\$8,676)	(\$23,823)	(\$36,572)	(\$1,303)	(\$52)	(\$167,870)
15		Total Incremental Optimization Costs	\$341,765	\$363,466	\$145,687	\$174,656	\$211,756	\$131,824	\$121,826	\$138,403	\$119,297	\$109,244	\$166,679	\$147,159	\$2,171,762
16															
17		Dodd Frank Fees	\$399												\$399
18															
19	Adjustments to Fuel Cost	Energy Imbalance Fuel Revenues	(\$80,338)	(\$47,699)	(\$54,762)	(\$81,589)	(\$59,321)	(\$71,312)	(\$88,719)	(\$14,737)	(\$113,683)	(\$147,420)	(\$163,749)	(\$93,294)	(\$1,016,625)
20		Inventory Adjustments	\$67,324	(\$29,576)	\$14,326	\$9,656	\$107,445	(\$40,469)	\$45,407	\$20,173	\$54,607	(\$1,711)	(\$118,879)	\$110,409	\$238,711
21		Other O&M Expense ⁽²⁾						\$230,839	\$118,492	\$16,385	\$26,080	\$175,447			\$567,243
22		Adjusted Total Fuel Costs & Net Power Transactions	\$174,439,670	\$162,019,630	\$178,769,926	\$175,035,309	\$196,885,943	\$212,071,731	\$210,593,831	\$248,848,907	\$246,952,525	\$237,401,684	\$229,638,528	\$207,599,173	\$2,480,256,857
23		Non Recoverable Oil/Tank Bottoms													
24															
25	kWh Sales	Jurisdictional kWh Sales	8,171,566,237	7,512,483,753	7,875,964,458	9,182,676,725	9,179,513,583	10,172,896,382	11,263,504,051	11,371,135,026	11,283,813,059	10,086,383,608	9,490,139,017	7,940,876,420	113,530,952,319
26		Sales for Resale (excluding Stratified Sales)	406,373,114	410,569,706	399,184,391	454,450,732	468,191,181	487,119,537	550,868,492	571,996,312	580,959,986	513,824,366	503,234,533	415,977,711	5,762,750,061
27		Total Sales	8,577,939,351	7,923,053,459	8,275,148,849	9,637,127,457	9,647,704,764	10,660,015,919	11,814,372,543	11,943,131,338	11,864,773,045	10,600,207,974	9,993,373,550	8,356,854,131	119,293,702,380
28															
29		Jurisdictional % of Total kWh Sales	95.26258%	94.81804%	95.17611%	95.28438%	95.14712%	95.43041%	95.33730%	95.21067%	95.10349%	95.15270%	94.96432%	95.02232%	95.16928%
30															
31	True-Up Calculation	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	\$177,353,979	\$161,495,094	\$170,048,894	\$203,756,280	(\$2,911,081)	\$227,040,535	\$255,382,332	\$257,347,691	\$255,080,768	\$224,228,261	\$208,738,514	\$171,264,163	\$2,308,825,430
32															
33	Fuel Adjustment Revenues Not Applicable to Period														
34		Prior Period True-Up (Collected)/Refunded This Period ⁽³⁾	\$4,840,211	\$4,840,211	\$4,840,211	\$4,840,211	\$4,840,211	\$4,840,211	\$4,840,211	\$4,840,211	\$4,840,211	\$4,840,211	\$4,840,211	\$4,840,211	\$58,082,532
35		GPIF, Net of Revenue Taxes ⁽⁴⁾	(\$714,241)	(\$714,241)	(\$714,241)	(\$714,241)	(\$714,241)	(\$714,241)	(\$714,241)	(\$714,241)	(\$714,241)	(\$714,241)	(\$714,241)	(\$714,241)	(\$8,570,896)
36		Solar Together - Subscription Credit, Net of Revenue Taxes ⁽⁵⁾				(\$2,926,367)	(\$2,838,531)	(\$3,117,085)	(\$2,736,739)	(\$2,882,411)	(\$2,787,842)	(\$2,355,725)	(\$2,267,054)	(\$2,004,221)	(\$23,915,976)
37		Incentive Mechanism, Net of Revenue Taxes ⁽⁶⁾	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$1,064,771)	(\$12,777,254)
38		Retail Fuel Revenues Applicable to Period	\$180,415,177	\$164,556,293	\$173,110,093	\$203,891,112	(\$2,688,413)	\$226,984,648	\$255,706,791	\$257,526,478	\$255,354,124	\$224,933,734	\$209,532,658	\$172,321,141	\$2,321,643,836
39		Adjusted Total Fuel Costs & Net Power Transactions	174,439,670	162,019,630	178,769,926	175,035,309	196,885,943	212,071,731	210,593,831	248,848,907	246,952,525	237,401,684	229,638,528	207,599,173	2,480,256,857
40		Retail % of Total kWh Sales	95.26258%	94.81804%	95.17611%	95.28438%	95.14712%	95.43041%	95.33730%	95.21067%	95.10349%	95.15270%	94.96432%	95.02232%	95.16928%
41		Juris. Total Fuel Costs & Net Power Transactions	166,395,082	153,826,621	170,370,854	167,026,478	187,606,681	202,678,422	201,069,611	237,278,999	235,205,715	226,226,177	218,395,236	197,555,531	2,363,635,408
42		True-Up Provision for the Month-Over(Under) Recovery	\$14,020,095	\$10,729,671	\$2,739,239	\$36,864,634	(\$190,295,095)	\$24,306,225	\$54,637,180	\$20,247,479	\$20,148,409	(\$1,292,442)	(\$8,862,578)	(\$25,234,390)	(\$41,991,572)
43		Interest Provision for the Month	\$14,873	\$24,800	\$32,233	\$33,590	(\$2,684)	(\$11,712)	(\$9,823)	(\$6,663)	(\$5,128)	(\$4,086)	(\$5,898)	(\$7,852)	\$51,549
44		True-Up & Interest Prov. Beg of Period-Over(Under) Recovery	\$58,082,532	\$67,277,289	\$73,191,550	\$71,122,810	\$103,180,822	(\$91,957,167)	(\$72,502,864)	(\$22,715,818)	(\$7,315,213)	\$7,987,857	\$1,851,117	(\$11,857,570)	\$58,082,532
45		Deferred True-up Beginning of Period - Over(Under) Recovery ⁽⁷⁾	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)	(\$51,621,690)
46		Prior Period True-Up Collected(Refunded) This Period	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$4,840,211)	(\$58,082,532)
47		End of Period Net True-up Amount Over(Under) Recovery	\$15,655,598	\$21,569,859	\$19,501,119	\$15,559,132	(\$143,578,857)	(\$124,124,555)	(\$74,337,508)	(\$58,936,904)	(\$43,633,834)	(\$49,770,573)	(\$63,479,260)	(\$93,561,713)	(\$93,561,713)
48															
49															

⁽¹⁾ Actuals include various adjustments as noted on the A-Schedules.⁽²⁾ Other Fuel Expense consists of nuclear fuel design software maintenance costs.⁽³⁾ Prior Period 2019 Actual/Estimated True-up.⁽⁴⁾ Generating Performance Incentive Factor is ((\$8,577,071/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI⁽⁵⁾ Jurisdictionalized Incentive Mechanism - FPL Portion is ((\$12,786,460/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI⁽⁶⁾ Approved in Order No. PSC-2020-0084-S-EI issued in Docket No. 20190061-EI on March 20, 2020⁽⁷⁾ 2019 Final True-up.

Totals may not add due to rounding.

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	True-up	True Up Line	2020			
			Actuals	Actual/Estimated	Diff \$	Diff %
1	Fuel Costs & Net Power Transactions	Fuel Cost of System Net Generation ⁽¹⁾	\$2,536,809,683	\$2,396,688,611	\$140,121,073	5.8%
2		Fuel Cost of Stratified Sales	(\$30,790,542)	(\$36,082,691)	\$5,292,149	(14.7%)
3		Rail Car Lease (Cedar Bay/ICL/SJRPP)	\$2,141,847	\$2,083,460	\$58,387	2.8%
4		Fuel Cost of Power Sold (Per A6)	(\$46,444,900)	(\$50,569,119)	\$4,124,219	(8.2%)
5		Gains from Off-System Sales (Per A6)	(\$25,555,054)	(\$24,898,147)	(\$656,908)	2.6%
6		Fuel Cost of Purchased Power (Per A7)	\$28,306,481	\$27,291,794	\$1,014,687	3.7%
7		Energy Payments to Qualifying Facilities (Per A8)	\$4,101,922	\$4,701,482	(\$599,559)	(12.8%)
8		Energy Cost of Economy Purchases (Per A9)	\$9,725,929	\$10,530,786	(\$804,857)	(7.6%)
9		Total Fuel Costs & Net Power Transactions	<u>\$2,478,295,367</u>	<u>\$2,329,746,176</u>	<u>\$148,549,191</u>	6.4%
10						
11	Incremental Optimization Costs	Incremental Personnel, Software, and Hardware Costs	\$512,326	\$493,717	\$18,609	3.8%
12		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	\$1,827,307	\$1,841,614	(\$14,307)	(0.8%)
13		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	(\$167,870)	(\$240,352)	\$72,482	(30.2%)
14		Total Incremental Optimization Costs	<u>\$2,171,762</u>	<u>\$2,094,979</u>	<u>\$76,784</u>	3.7%
15		Dodd Frank Fees	\$399	\$399	-	0.0%
16						
17	Adjustments to Fuel Cost	Energy Imbalance Fuel Revenues	(\$1,016,625)	(\$395,022)	(\$621,603)	157.4%
18		Inventory Adjustments	\$238,711	\$128,705	\$110,005	85.5%
19		Other O&M Expense ⁽²⁾	\$567,243	\$579,829	(\$12,586)	(2.2%)
20		Adjusted Total Fuel Costs & Net Power Transactions	<u>\$2,480,256,857</u>	<u>\$2,332,155,067</u>	<u>\$148,101,790</u>	6.4%
21						
22						
23	kWh Sales	Jurisdictional kWh Sales	113,530,952,319	111,535,152,471	1,995,799,848	1.8%
24		Sales for Resale (excluding Stratified Sales)	5,762,750,061	5,228,858,323	533,891,738	10.2%
25		Total Sales	<u>119,293,702,380</u>	<u>116,764,010,794</u>	<u>2,529,691,586</u>	2.2%
26						
27		Jurisdictional % of Total Sales	95.16928%	95.52186%		
28						
29	True-Up Calculation	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	\$2,308,825,430	\$2,250,056,998	\$58,768,432	2.6%
30						
31	Fuel Adjustment Revenues Not Applicable to Period					
32		Prior Period True-Up (Collected)/Refunded This Period ⁽³⁾	\$58,082,532	\$58,082,532	-	0.0%
33		GPIF, Net of Revenue Taxes ⁽⁴⁾	(\$8,570,896)	(\$8,570,896)	-	0.0%
34		Solar Together - Subscription Credit, Net of Revenue Taxes ⁽⁵⁾	(\$23,915,976)	(\$25,061,936)	\$1,145,959	(4.6%)
35		Incentive Mechanism, Net of Revenue Taxes ⁽⁵⁾	(\$12,777,254)	(\$12,777,254)	-	0.0%
36		Jurisdictional Fuel Revenues Applicable to Period	<u>\$2,321,643,836</u>	<u>\$2,261,729,445</u>	<u>\$59,914,391</u>	(2.0%)
37		Adjusted Total Fuel Costs & Net Power Transactions	2,480,256,857	2,332,155,067	148,101,790	6.4%
38		Jurisdictional Sales % of Total kWh Sales	<u>95.16928%</u>	<u>95.52186%</u>		
39		Juris. Total Fuel Costs & Net Power Transactions	<u>\$2,363,635,408</u>	<u>\$2,230,843,677</u>	<u>\$132,791,731</u>	6.0%
40		True-Up Provision for the Month-Over/(Under) Recovery	(\$41,991,572)	\$30,885,767	(\$72,877,339)	(236.0%)
41		Interest Provision for the Month	\$51,549	\$66,013	(\$14,464)	(21.9%)
42		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	\$58,082,532	\$58,082,532	-	0.0%
43		Deferred True-up Beginning of Period - Over/(Under) Recovery ⁽⁷⁾	(\$51,621,690)	(\$51,621,690)	-	0.0%
44		Prior Period True-Up Collected/(Refunded) This Period	<u>(\$58,082,532)</u>	<u>(\$58,082,532)</u>	<u>-</u>	0.0%
45		End of Period Net True-up Amount Over/(Under) Recovery	<u>(\$93,561,713)</u>	<u>(\$20,669,910)</u>	<u>(\$72,891,803)</u>	352.6%
46						
47						

⁽¹⁾ Actuals include various adjustments as noted on the A-Schedules.

⁽²⁾ Other Fuel Expense consists of nuclear fuel design software maintenance costs.

⁽³⁾ Prior Period 2019 Actual/Estimated True-up.

⁽⁴⁾ Generating Performance Incentive Factor is ((\$8,577,071/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI

⁽⁵⁾ Jurisdictionalized Incentive Mechanism - FPL Portion is ((\$12,786,460/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI

⁽⁶⁾ Approved in Order No. PSC-2020-0084-S-EI issued in Docket No. 20190061-EI on March 20, 2020

⁽⁷⁾ 2019 Final True-up.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
FINAL TRUE-UP SUMMARY

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Line	YE-Dec - 2020
1	End of Period True-Up for the Period ⁽¹⁾	\$11,252,066
2	Less - Estimated/Actual True Up for Same Period ⁽²⁾	\$7,388,454
3	Net True Up for the Period	<u>\$3,863,612</u>
4		
5	⁽¹⁾ From page 4, Column 15, Lines 9 & 10	
6	⁽²⁾ Approved in FPSC Final Order PSC-2020-0439-FOF-EI	
7		
8	() Reflects under-recovery	
9		
10	Totals may not add due to rounding	

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Capacity Costs	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	a-Jul - 2020	a-Aug - 2020	a-Sep - 2020	a-Oct - 2020	a-Nov - 2020	a-Dec - 2020	Total
1	Base													
2	Payments to Non-cogenerators	\$2,083,820	\$2,083,820	\$2,083,820	\$2,083,820	\$2,412,200	\$2,145,800	\$2,456,600	\$2,412,200	\$2,412,200	\$2,192,619	\$2,193,280	\$2,193,280	\$26,753,458
3	Payments to Co-generators	\$167,174	\$119,175	\$119,175	\$119,175	\$119,175	\$119,175	\$119,175	\$119,175	\$119,175	\$119,175	\$119,175	\$119,175	\$1,478,099
4	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	\$9,409,836	\$9,378,844	\$9,347,853	\$9,316,861	\$9,285,870	\$9,254,879	\$9,212,873	\$9,182,087	\$9,151,301	\$9,120,516	\$9,089,730	\$9,058,945	\$110,809,595
5	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	(\$85,020)	(\$84,614)	(\$84,208)	(\$83,802)	(\$83,396)	(\$82,990)	(\$82,440)	(\$82,037)	(\$81,634)	(\$81,230)	(\$80,827)	(\$80,424)	(\$992,622)
6	Indiantown Transaction - Regulatory Asset - Amortization and Return	\$6,173,883	\$6,146,004	\$6,118,125	\$6,090,246	\$6,062,368	\$6,034,489	\$5,994,480	\$5,966,786	\$5,939,093	\$5,911,399	\$5,883,706	\$5,856,012	\$72,176,590
7	SJRPP Revenue Requirements	\$863,715	\$852,045	\$840,376	\$828,706	\$817,037	\$805,367	\$792,496	\$780,904	\$769,312	\$757,720	\$746,128	\$734,536	\$9,588,342
8	Incremental Plant Security Costs O&M	\$2,520,078	\$1,940,794	\$2,385,822	\$2,117,404	\$2,050,331	\$2,176,905	\$2,374,234	\$2,025,124	\$2,496,052	\$2,125,457	\$2,021,472	\$2,858,224	\$27,091,896
9	Incremental Plant Security Costs Capital	\$325,279	\$327,832	\$329,753	\$332,628	\$336,952	\$340,309	\$353,184	\$365,728	\$365,543	\$368,161	\$371,731	\$374,167	\$4,191,267
10	Incremental Nuclear NRC Compliance Costs O&M	\$70,186	\$67,009	\$62,443	\$93,471	\$68,310	\$34,558	\$35,686	\$54,932	\$49,368	\$88,612	\$198,484	\$58,457	\$901,517
11	Incremental Nuclear NRC Compliance Costs Capital	\$1,072,250	\$1,071,956	\$1,078,562	\$1,081,599	\$1,080,512	\$1,080,755	\$1,078,293	\$1,083,197	\$1,084,810	\$1,091,480	\$1,077,235	\$1,054,194	\$12,934,844
12	Transmission of Electricity by Others	\$88,540	\$77,707	-	-	\$661	(\$548)	\$301	-	-	-	-	(\$398,710)	(\$232,049)
13	Transmission Revenues from Capacity Sales	(\$1,111,540)	(\$1,242,433)	(\$643,816)	(\$666,331)	(\$574,685)	(\$278,044)	(\$127,004)	(\$89,372)	(\$82,433)	(\$126,151)	(\$334,220)	(\$1,266,448)	(\$6,542,478)
14	Total Base	\$21,578,200	\$20,738,139	\$21,657,906	\$21,313,779	\$21,575,334	\$21,630,655	\$22,207,878	\$21,818,724	\$22,222,787	\$21,567,758	\$21,285,893	\$20,561,407	\$258,158,459
15														
16	Intermediate													
17	Incremental Plant Security Costs O&M	\$260,708	\$417,161	\$297,760	\$374,231	\$614,490	\$562,818	\$271,784	\$161,013	\$80,827	\$88,616	\$144,740	\$173,979	\$3,448,127
18	Incremental Plant Security Costs Capital	\$45,631	\$45,530	\$45,429	\$45,328	\$45,227	\$45,126	\$44,827	\$46,734	\$48,645	\$48,994	\$49,681	\$51,640	\$562,792
19	Total Intermediate	\$306,340	\$462,691	\$343,189	\$419,559	\$659,717	\$607,944	\$316,611	\$207,748	\$129,471	\$137,610	\$194,421	\$225,619	\$4,010,920
20														
21	Peaking													
22	Incremental Plant Security Costs O&M	\$41,346	\$21,654	\$27,891	\$26,212	\$28,712	\$39,282	\$28,055	\$31,275	\$28,224	\$39,708	\$28,795	\$21,886	\$363,041
23	Incremental Plant Security Costs Capital	\$6,432	\$6,413	\$6,393	\$6,373	\$6,354	\$6,334	\$6,292	\$6,396	\$6,500	\$6,481	\$6,461	\$6,442	\$76,871
24	Total Peaking	\$47,778	\$28,066	\$34,284	\$32,586	\$35,066	\$45,616	\$34,347	\$37,671	\$34,724	\$46,188	\$35,256	\$28,328	\$439,912
25														
26	Solar													
27	Incremental Plant Security Costs O&M	-	\$1,256	\$340	-	\$130	\$10,886	\$668	\$6,628	\$139	\$140	\$35,964	\$1,071	\$57,223
28	Incremental Plant Security Costs Capital	\$403	\$785	\$1,131	\$1,397	\$1,614	\$1,665	\$1,783	\$1,863	\$2,944	\$4,043	\$4,055	\$5,032	\$26,714
29	Total Solar	\$403	\$2,041	\$1,471	\$1,397	\$1,744	\$12,551	\$2,451	\$8,491	\$3,083	\$4,183	\$40,018	\$6,103	\$83,938
30														
31	General													
32	Incremental Plant Security Costs Capital	\$2,598	\$2,582	\$2,565	\$2,549	\$2,533	\$2,517	\$2,500	\$2,484	\$2,468	\$2,452	\$2,436	\$2,312	\$29,998
33	Total General	\$2,598	\$2,582	\$2,565	\$2,549	\$2,533	\$2,517	\$2,500	\$2,484	\$2,468	\$2,452	\$2,436	\$2,312	\$29,998
34														
35	Total	\$21,935,319	\$21,233,519	\$22,039,415	\$21,769,870	\$22,274,395	\$22,299,283	\$22,563,787	\$22,075,119	\$22,392,534	\$21,758,191	\$21,558,025	\$20,823,770	\$262,723,226
36														
37														
38	Totals may not add due to rounding													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	a-Jul - 2020	a-Aug - 2020	a-Sep - 2020	a-Oct - 2020	a-Nov - 2020	a-Dec - 2020	Total
1	Total Capacity Costs (Page 2, Line 35)	\$21,935,319	\$21,233,519	\$22,039,415	\$21,769,870	\$22,274,395	\$22,299,283	\$22,563,787	\$22,075,119	\$22,392,534	\$21,758,191	\$21,558,025	\$20,823,770	\$262,723,226
2														
3	Total Base Capacity Costs	\$21,578,200	\$20,738,139	\$21,657,906	\$21,313,779	\$21,575,334	\$21,630,655	\$22,207,878	\$21,818,724	\$22,222,787	\$21,567,758	\$21,285,893	\$20,561,407	\$258,158,459
4	Base Jurisdictional Factor ⁽¹⁾	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%
5	Total Base Jurisdictional Capacity Costs	\$20,670,233	\$19,865,519	\$20,746,584	\$20,416,938	\$20,667,487	\$20,720,480	\$21,273,414	\$20,900,636	\$21,287,696	\$20,660,229	\$20,390,225	\$19,696,225	\$247,295,667
6														
7	Total Intermediate Capacity Costs	\$306,340	\$462,691	\$343,189	\$419,559	\$659,717	\$607,944	\$316,611	\$207,748	\$129,471	\$137,610	\$194,421	\$225,619	\$4,010,920
8	Intermediate Jurisdictional Factor ⁽¹⁾	94.1569%	94.1569%	94.1569%	94.1569%	94.1569%	94.1569%	94.1569%	94.1569%	94.1569%	94.1569%	94.1569%	94.1569%	94.1569%
9	Total Intermediate Jurisdictional Capacity Costs	\$288,440	\$435,656	\$323,136	\$395,044	\$621,169	\$572,421	\$298,111	\$195,609	\$121,906	\$129,569	\$183,061	\$212,436	\$3,776,558
10														
11	Total Peaking Capacity Costs	\$47,778	\$28,066	\$34,284	\$32,586	\$35,066	\$45,616	\$34,347	\$37,671	\$34,724	\$46,188	\$35,256	\$28,328	\$439,912
12	Peaking Jurisdictional Factor ⁽¹⁾	95.0455%	95.0455%	95.0455%	95.0455%	95.0455%	95.0455%	95.0455%	95.0455%	95.0455%	95.0455%	95.0455%	95.0455%	95.0455%
13	Total Peaking Jurisdictional Capacity Costs	\$45,411	\$26,676	\$32,586	\$30,971	\$33,329	\$43,356	\$32,645	\$35,805	\$33,004	\$43,900	\$33,510	\$26,925	\$418,117
14														
15	Total Solar Capacity Costs	\$403	\$2,041	\$1,471	\$1,397	\$1,744	\$12,551	\$2,451	\$8,491	\$3,083	\$4,183	\$40,018	\$6,103	\$83,938
16	Solar Jurisdictional Factor ⁽¹⁾	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%	95.7922%
17	Total Solar Jurisdictional Capacity Costs	\$386	\$1,955	\$1,409	\$1,338	\$1,671	\$12,023	\$2,348	\$8,134	\$2,953	\$4,007	\$38,335	\$5,846	\$80,406
18														
19	Total Transmission Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Transmission Jurisdictional Factor ⁽¹⁾	89.9387%	89.9387%	89.9387%	89.9387%	89.9387%	89.9387%	89.9387%	89.9387%	89.9387%	89.9387%	89.9387%	89.9387%	89.9387%
21	Total Transmission Jurisdictional Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
22														
23	Total General Capacity Costs	\$2,598	\$2,582	\$2,565	\$2,549	\$2,533	\$2,517	\$2,500	\$2,484	\$2,468	\$2,452	\$2,436	\$2,312	\$29,998
24	General Jurisdictional Factor ⁽¹⁾	96.9124%	96.9124%	96.9124%	96.9124%	96.9124%	96.9124%	96.9124%	96.9124%	96.9124%	96.9124%	96.9124%	96.9124%	96.9124%
25	Total General Jurisdictional Capacity Costs	\$2,518	\$2,502	\$2,486	\$2,471	\$2,455	\$2,439	\$2,423	\$2,408	\$2,392	\$2,376	\$2,361	\$2,241	\$29,072
26														
27	Jurisdictional Capacity Costs	\$21,006,987	\$20,332,308	\$21,106,201	\$20,846,761	\$21,326,111	\$21,350,720	\$21,608,942	\$21,142,591	\$21,447,952	\$20,840,082	\$20,647,491	\$19,943,672	\$251,599,819
28														
29														
30														
31	⁽¹⁾ Approved in FPSC Final Order PSC-2020-0439-FOF-EI													
32														
33														
34	Totals may not add due to rounding													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-January Actual	a-February Actual	a-March Actual	a-April Actual	a-May Actual	a-June Actual	a-July Actual	a-August Actual	a-September Actual	a-October Actual	a-November Actual	a-December Actual	Total
1														
2	Net Jurisdictional CCR Costs (Page 3, Line 31)	\$21,006,987	\$20,332,308	\$21,106,201	\$20,846,761	\$21,326,111	\$21,350,720	\$21,608,942	\$21,142,591	\$21,447,952	\$20,840,082	\$20,647,491	\$19,943,672	\$251,599,819
3														
4	CCR Revenues (Net of Revenue Taxes)	\$17,225,349	\$16,294,404	\$17,058,910	\$19,576,540	\$19,584,553	\$21,402,820	\$23,519,121	\$23,624,051	\$23,450,364	\$21,259,825	\$19,867,428	\$17,045,766	\$239,909,130
5	Prior Period True-up Provision	\$1,347,028	\$1,347,028	\$1,347,028	\$1,347,028	\$1,347,028	\$1,347,028	\$1,347,028	\$1,347,028	\$1,347,028	\$1,347,028	\$1,347,028	\$1,347,028	\$16,164,334
6	2017 SoBRA Refund	\$554,832	\$554,832	\$554,832	\$554,832	\$554,832	\$554,832	\$554,832	\$554,832	\$554,832	\$554,832	\$554,832	\$554,832	\$6,657,982
7	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	\$19,127,209	\$18,196,263	\$18,960,770	\$21,478,400	\$21,486,413	\$23,304,679	\$25,420,980	\$25,525,910	\$25,352,224	\$23,161,684	\$21,769,287	\$18,947,626	\$262,731,446
8														
9	True-up Provision - Over/(Under) Recovery (Line 6 - Line 2)	(\$1,879,778)	(\$2,136,045)	(\$2,145,432)	\$631,638	\$160,302	\$1,953,960	\$3,812,038	\$4,383,319	\$3,904,272	\$2,321,602	\$1,121,796	(\$996,046)	\$11,131,627
10	Interest Provision	\$35,090	\$29,598	\$28,566	\$14,712	\$820	\$1,157	\$1,420	\$1,640	\$1,864	\$1,737	\$2,050	\$1,784	\$120,439
11	True-up & Interest Provision Beginning of Year - Over/(Under) Recovery	\$22,822,316	\$19,075,768	\$15,067,461	\$11,048,736	\$9,793,227	\$8,052,489	\$8,105,746	\$10,017,345	\$12,500,444	\$14,504,721	\$14,926,201	\$14,148,188	\$22,822,316
12	Deferred True-up - Over/(Under) Recovery	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967	\$5,141,967
13	2017 SoBRA Refund	(\$554,832)	(\$554,832)	(\$554,832)	(\$554,832)	(\$554,832)	(\$554,832)	(\$554,832)	(\$554,832)	(\$554,832)	(\$554,832)	(\$554,832)	(\$554,832)	(\$6,657,982)
14	Prior Period True-up Provision - Collected/(Refunded)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$1,347,028)	(\$16,164,334)
15	End of Period True-up - Over/(Under) Recovery (Lines 8 through 12)	\$24,217,735	\$20,209,428	\$16,190,703	\$14,935,194	\$13,194,456	\$13,247,713	\$15,159,312	\$17,642,411	\$19,646,688	\$20,068,168	\$19,290,155	\$16,394,033	\$16,394,033
16														
17	Totals may not add due to rounding													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF VARIANCES

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Capacity Costs	Actual	Actual/Estimated	Diff \$	Diff %
1	Payments to Non-cogenerators	\$26,753,458	\$26,709,720	\$43,738	0.2%
2	Payments to Co-generators	\$1,478,099	\$1,478,099	\$0	0.0%
3	Cedar Bay Transaction - Reg Asset - Amort & Return	\$110,809,595	\$110,809,595	\$0	0.0%
4	Cedar Bay Transaction - Reg Liability - Amort & Return	(\$992,622)	(\$992,622)	\$0	0.0%
5	Incremental Nuclear NRC Compliance Costs O&M	\$901,517	\$1,614,023	(\$712,506)	(44.1%)
6	Incremental Nuclear NRC Compliance Costs Capital	\$12,934,844	\$12,974,927	(\$40,083)	(0.3%)
7	Transmission of Electricity by Others	(\$232,049)	\$293,218	(\$525,267)	(179.1%)
8	Transmission Revenues from Capacity Sales	(\$6,542,478)	(\$7,978,840)	\$1,436,362	(18.0%)
9	Incremental Plant Security Costs-Order No. PSC-02-1761 (O&M)	\$30,960,288	\$33,488,647	(\$2,528,359)	(7.5%)
10	Incremental Plant Security Costs-Order No. PSC-02-1761 (Capital)	\$4,887,642	\$4,869,845	\$17,798	0.4%
11	Indiantown Transaction - Regulatory Asset - Amortization and Return	\$72,176,590	\$72,176,590	\$0	0.0%
12	SJRPP Transaction Revenue Requirements	\$9,588,342	\$9,588,342	\$0	0.0%
13	Total	\$262,723,226	\$265,031,544	(\$2,308,318)	(0.9%)
14					
15	Totals may not add due to rounding				

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF VARIANCES

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Line	Actual	Actual/Estimated	Diff \$	Diff %
1	Total Capacity Costs	\$262,723,226	\$265,031,544	(\$2,308,318)	(0.9%)
2					
3	Total Base Capacity Costs	\$258,158,459	\$259,991,148	(\$1,832,689)	(0.7%)
4	Base Jurisdictional Factor	95.7922%	95.7922%		
5	Total Base Jurisdictionalized Capacity Costs	\$247,295,667	\$249,051,311	(\$1,755,643)	(0.7%)
6					
7	Total Intermediate Capacity Costs	\$4,010,920	\$4,277,371	(\$266,451)	(6.2%)
8	Intermediate Jurisdictional Factor	94.1569%	94.15685%		
9	Total Intermediate Jurisdictionalized Capacity Costs	\$3,776,558	\$4,027,438	(\$250,880)	(6.2%)
10					
11	Total Peaking Capacity Costs	\$439,912	\$530,902	(\$90,990)	(17.1%)
12	Peaking Jurisdictional Factor	95.0455%	95.0455%		
13	Total Peaking Jurisdictionalized Capacity Costs	\$418,117	\$504,599	(\$86,482)	(17.1%)
14					
15	Total Solar Capacity Costs	\$83,938	\$203,504	(\$119,566)	(58.8%)
16	Solar Jurisdictional Factor	95.7922%	95.7922%		
17	Total Solar Jurisdictionalized Capacity Costs	\$80,406	\$194,941	(\$114,535)	(58.8%)
18					
19	Total General Capacity Costs	\$29,998	\$28,619	\$1,378	4.8%
20	General Jurisdictional Factor	96.9124%	96.9124%		
21	Total General Jurisdictionalized Capacity Costs	\$29,072	\$27,736	\$1,336	4.8%
22					
23	Total Transmission Capacity Costs	\$0	\$0	\$0	0.0%
24	Transmission Jurisdictional Factor	89.9387%	89.9387%		
25	Total Transmission Jurisdictionalized Costs	\$0	\$0	\$0	N/A
26					
27	Jurisdictional Capacity Charges	\$251,599,819	\$253,806,024	(\$2,206,205)	(0.9%)
28					
29					
30	CCR Revenues	\$239,909,130	\$238,252,700	\$1,656,429	0.7%
31	Prior Period True-up Provision	\$16,164,334	\$16,164,334	\$0	0.0%
32	2017 SoBRA Refund	\$6,657,982	\$6,657,982	\$0	0.0%
33	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	\$262,731,446	\$261,075,016	\$1,656,429	0.7%
34					
35	True-up Provision for Month - Over/(Under) Recovery	\$11,131,627	\$7,268,993	\$3,862,634	53.1%
36	Interest Provision for the Month	\$120,439	\$119,461	\$978	0.8%
37	Prior Period True-Up Provision	\$22,822,316	\$22,822,316	\$0	0.0%
38	Deferred True-up - Over/(Under) Recovery	\$5,141,967	\$5,141,967	\$0	0.0%
39	Cape Canaveral GBRA Refund Current Month	(\$6,657,982)	(\$6,657,982)	\$0	0.0%
40	Prior Period True-up Provision - Collected/(Refunded) this Month	(\$16,164,334)	(\$16,164,334)	\$0	0.0%
41	End of Period True-up - Over/(Under) Recovery	\$16,394,033	\$12,530,421	\$3,863,612	30.8%
42					
43					
44	Totals may not add due to rounding				

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Strata	Line	Beginning of Period	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Base	Investments														
2		a. Expenditures/Additions		\$370,983	\$592,059	\$183,653	\$875,451	\$615,449	\$587,979	(\$13,278,089)	\$915	-	(\$2,119,910)	\$1,234,729	(\$213,637)	(\$11,150,418)
3		b. Clearings to Plant		-	-	-	-	-	-	\$13,455,642	\$32,857	\$121,593	\$2,342,468	(\$27,220)	\$65,339	\$15,990,679
4		c. Retirements		-	-	-	-	-	-	-	-	-	-	-	(\$313,513)	(\$313,513)
5		d. Other		(\$3,272)	(\$5,360)	(\$1,240)	(\$7,938)	(\$3,771)	(\$5,896)	(\$1,681)	(\$316)	(\$1,236)	(\$6,661)	(\$35,802)	(\$2,928)	(\$76,103)
6																
7		Plant-In-Service/Depreciation Base	\$22,916,916	\$22,916,916	\$22,916,916	\$22,916,916	\$22,916,916	\$22,916,916	\$22,916,916	\$36,372,558	\$36,405,415	\$36,527,008	\$38,869,476	\$38,842,256	\$38,907,595	
8		Less: Accumulated Depreciation	\$2,866,622	\$2,966,356	\$3,064,003	\$3,165,770	\$3,260,838	\$3,360,074	\$3,457,185	\$3,571,125	\$3,699,076	\$3,826,251	\$3,950,312	\$4,044,790	\$3,857,247	
9		CWIP - Non Interest Bearing	\$13,144,889	\$13,515,872	\$14,107,931	\$14,291,584	\$15,167,035	\$15,782,484	\$16,370,464	\$3,092,375	\$3,093,290	\$3,093,290	\$973,380	\$2,208,109	\$1,994,471	
10																
11		Net Investment (Lines 7 - 8 + 9)	\$33,195,184	\$33,466,431	\$33,960,844	\$34,042,731	\$34,823,113	\$35,339,326	\$35,830,195	\$35,893,808	\$35,799,629	\$35,794,046	\$35,892,544	\$37,005,575	\$37,044,819	
12																
13		Average Net Investment		\$33,330,808	\$33,713,638	\$34,001,787	\$34,432,922	\$35,081,219	\$35,584,760	\$35,862,001	\$35,846,718	\$35,796,838	\$35,843,295	\$36,449,060	\$37,025,197	
14																
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes ⁽¹⁾		\$184,755	\$186,877	\$188,474	\$190,864	\$194,457	\$197,248	\$197,103	\$197,019	\$196,745	\$197,000	\$200,330	\$203,496	\$2,334,369
18		b. Debt Component (Line 13 x debt rate x 1/12) ⁽²⁾		\$37,517	\$37,948	\$38,272	\$38,758	\$39,487	\$40,054	\$40,460	\$40,442	\$40,386	\$40,438	\$41,122	\$41,772	\$476,657
19																
20		Investment Expenses														
21		a. Depreciation		\$103,007	\$103,007	\$103,007	\$103,007	\$103,007	\$103,007	\$115,621	\$128,267	\$128,412	\$130,722	\$130,280	\$128,899	\$1,380,242
22		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
23		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
24																
25		Total System Recoverable Costs (Lines 16+17+20)		<u>\$325,279</u>	<u>\$327,832</u>	<u>\$329,753</u>	<u>\$332,628</u>	<u>\$336,952</u>	<u>\$340,309</u>	<u>\$353,184</u>	<u>\$365,728</u>	<u>\$365,543</u>	<u>\$368,161</u>	<u>\$371,731</u>	<u>\$374,167</u>	<u>\$4,191,267</u>
26																
27																
28																

⁽¹⁾ The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

⁽²⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Strata	Line	Beginning of Period	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	General	Investments														
2		a. Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
3		b. Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	(\$12,959)	(\$12,959)
4		c. Retirements		-	-	-	-	-	-	-	-	-	-	-	(\$12,959)	(\$12,959)
5		d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	\$145,284	\$145,284	\$145,284	\$145,284	\$145,284	\$145,284	\$145,284	\$145,284	\$145,284	\$145,284	\$145,284	\$145,284	\$132,325	
8		Less: Accumulated Depreciation	\$117,632	\$120,053	\$122,475	\$124,896	\$127,317	\$129,739	\$132,160	\$134,582	\$137,003	\$139,424	\$141,846	\$144,267	\$133,621	
9		CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
10																
11		Net Investment (Lines 7 - 8 + 9)	\$27,652	\$25,231	\$22,809	\$20,388	\$17,966	\$15,545	\$13,124	\$10,702	\$8,281	\$5,859	\$3,438	\$1,017	(\$1,297)	
12																
13		Average Net Investment		\$26,441	\$24,020	\$21,599	\$19,177	\$16,756	\$14,334	\$11,913	\$9,492	\$7,070	\$4,649	\$2,227	(\$140)	
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes ⁽¹⁾		\$147	\$133	\$120	\$106	\$93	\$79	\$65	\$52	\$39	\$26	\$12	(\$1)	\$872
17		b. Debt Component (Line 13 x debt rate x 1/12) ⁽²⁾		\$30	\$27	\$24	\$22	\$19	\$16	\$13	\$11	\$8	\$5	\$3	(\$0)	\$177
18																
19		Investment Expenses														
20		a. Depreciation		\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,313	\$28,949
21		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Total System Recoverable Costs (Lines 16+17+20)		\$2,598	\$2,582	\$2,565	\$2,549	\$2,533	\$2,517	\$2,500	\$2,484	\$2,468	\$2,452	\$2,436	\$2,312	\$29,998
25																
26																
27																

⁽¹⁾ The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

⁽²⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Strata	Line	Beginning of Period	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Intermediate	Investments														
2		a. Expenditures/Additions		-	-	-	-	-	-	-	\$82,776	\$1,261	\$122,071	\$103,596	(\$84,971)	\$224,732
3		b. Clearings to Plant		-	-	-	-	-	-	-	\$309,905	-	-	-	\$413,335	\$723,240
4		c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		d. Other		-	-	-	-	-	-	-	(\$34,434)	(\$140)	(\$13,573)	(\$2)	(\$11,700)	(\$59,849)
6																
7		Plant-In-Service/Depreciation Base	\$5,340,984	\$5,340,984	\$5,340,984	\$5,340,984	\$5,340,984	\$5,340,984	\$5,340,984	\$5,340,984	\$5,650,889	\$5,650,889	\$5,650,889	\$5,650,889	\$6,064,224	
8		Less: Accumulated Depreciation	\$764,038	\$779,198	\$794,358	\$809,518	\$824,678	\$839,838	\$854,997	\$870,157	\$851,224	\$866,926	\$869,195	\$885,035	\$889,772	
9		CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	\$159,415	\$160,675	\$282,746	\$386,342	\$301,371	
10																
11		Net Investment (Lines 7 - 8 + 9)	\$4,576,946	\$4,561,786	\$4,546,626	\$4,531,467	\$4,516,307	\$4,501,147	\$4,485,987	\$4,470,827	\$4,959,079	\$4,944,638	\$5,064,440	\$5,152,196	\$5,475,822	
12																
13		Average Net Investment		\$4,569,366	\$4,554,206	\$4,539,047	\$4,523,887	\$4,508,727	\$4,493,567	\$4,478,407	\$4,714,953	\$4,951,859	\$5,004,539	\$5,108,318	\$5,314,009	
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes ⁽¹⁾		\$25,328	\$25,244	\$25,160	\$25,076	\$24,992	\$24,908	\$24,614	\$25,914	\$27,216	\$27,506	\$28,076	\$29,207	\$313,242
17		b. Debt Component (Line 13 x debt rate x 1/12) ⁽²⁾		\$5,143	\$5,126	\$5,109	\$5,092	\$5,075	\$5,058	\$5,053	\$5,319	\$5,587	\$5,646	\$5,763	\$5,995	\$63,967
18																
19		Investment Expenses														
20		a. Depreciation		\$15,160	\$15,160	\$15,160	\$15,160	\$15,160	\$15,160	\$15,160	\$15,501	\$15,842	\$15,842	\$15,842	\$16,438	\$185,583
21		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Total System Recoverable Costs (Lines 16+17+20)		\$45,631	\$45,530	\$45,429	\$45,328	\$45,227	\$45,126	\$44,827	\$46,734	\$48,645	\$48,994	\$49,681	\$51,640	\$562,792
25																
26																
27																

⁽¹⁾ The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

⁽²⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY
Return on Capital Investments, Depreciation and Taxes
FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Strata	Line	Beginning of Period	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Peaking	Investments														
2		a.Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	(\$36)	(\$36)
3		b.Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
4		c.Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		d.Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	\$672,783	\$672,783	\$672,783	\$672,783	\$672,783	\$672,783	\$672,783	\$672,783	\$672,783	\$672,783	\$672,783	\$672,783	\$672,783	
8		Less: Accumulated Depreciation	\$146,041	\$148,970	\$151,899	\$154,828	\$157,758	\$160,687	\$163,616	\$166,545	\$169,474	\$172,404	\$175,333	\$178,262	\$181,191	
9		CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	\$37,190	\$37,190	\$37,190	\$37,190	\$37,154	
10																
11		Net Investment (Lines 7 - 8 + 9)	\$526,742	\$523,813	\$520,884	\$517,955	\$515,025	\$512,096	\$509,167	\$506,238	\$540,499	\$537,570	\$534,641	\$531,711	\$528,746	
12																
13		Average Net Investment		\$525,278	\$522,348	\$519,419	\$516,490	\$513,561	\$510,632	\$507,702	\$523,368	\$539,034	\$536,105	\$533,176	\$530,229	
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes ⁽¹⁾		\$2,912	\$2,895	\$2,879	\$2,863	\$2,847	\$2,830	\$2,790	\$2,877	\$2,963	\$2,947	\$2,930	\$2,914	\$34,647
17		b.Debt Component (Line 13 x debt rate x 1/12) ⁽²⁾		\$591	\$588	\$585	\$581	\$578	\$575	\$573	\$590	\$608	\$605	\$602	\$598	\$7,074
18																
19		Investment Expenses														
20		a.Depreciation		\$2,929	\$2,929	\$2,929	\$2,929	\$2,929	\$2,929	\$2,929	\$2,929	\$2,929	\$2,929	\$2,929	\$2,929	\$35,150
21		b.Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22		c.Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Total System Recoverable Costs (Lines 16+17+20)		\$6,432	\$6,413	\$6,393	\$6,373	\$6,354	\$6,334	\$6,292	\$6,396	\$6,500	\$6,481	\$6,461	\$6,442	\$76,871
25																
26																
27																

⁽¹⁾ The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

⁽²⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF VARIANCES
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Strata	Line	Beginning of Period	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Solar	Investments														
2		a. Expenditures/Additions		\$26,047	\$88,561	\$15,305	\$64,435	\$608	\$14,769	\$24,020	\$339	(\$181,450)	\$2,333	-	(\$102,341)	(\$47,374)
3		b. Clearings to Plant		-	-	-	-	-	-	-	-	\$181,759	\$2,043	-	\$143,904	\$327,705
4		c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	-	-	-	-	-	-	-	-	-	\$181,759	\$183,802	\$183,802	\$327,705	
8		Less: Accumulated Depreciation	-	-	-	-	-	-	-	-	-	\$1,082	\$3,258	\$5,446	\$8,491	
9		CWIP - Non Interest Bearing	\$47,374	\$73,421	\$161,981	\$177,287	\$241,722	\$242,330	\$257,099	\$281,119	\$281,458	\$100,008	\$102,341	\$102,341	-	
10																
11		Net Investment (Lines 7 - 8 + 9)	\$47,374	\$73,421	\$161,981	\$177,287	\$241,722	\$242,330	\$257,099	\$281,119	\$281,458	\$280,685	\$282,885	\$280,697	\$319,215	
12																
13		Average Net Investment		\$60,397	\$117,701	\$169,634	\$209,504	\$242,026	\$249,714	\$269,109	\$281,288	\$281,071	\$281,785	\$281,791	\$299,956	
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes ⁽¹⁾		\$335	\$652	\$940	\$1,161	\$1,342	\$1,384	\$1,479	\$1,546	\$1,545	\$1,549	\$1,549	\$1,649	\$15,131
17		b. Debt Component (Line 13 x debt rate x 1/12) ⁽²⁾		\$68	\$132	\$191	\$236	\$272	\$281	\$304	\$317	\$317	\$318	\$318	\$338	\$3,093
18																
19		Investment Expenses														
20		a. Depreciation		-	-	-	-	-	-	-	-	\$1,082	\$2,176	\$2,188	\$3,045	\$8,491
21		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Total System Recoverable Costs (Lines 16+17+20)		\$403	\$785	\$1,131	\$1,397	\$1,614	\$1,665	\$1,783	\$1,863	\$2,944	\$4,043	\$4,055	\$5,032	\$26,714
25																
26																
27																

⁽¹⁾ The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

⁽²⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL NUCLEAR NRC COMPLIANCE
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Line	Beginning of Period	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Investments														
2	a.Expenditures/Additions		\$475,685	\$606,045	(\$163,992)	(\$1,369,389)	\$459,328	\$284,406	(\$737,063)	\$1,368,835	\$164,111	\$2,241,813	(\$4,161,875)	\$1,112,694	\$280,597
3	b.Clearings to Plant		(\$336,616)	\$109,966	\$1,304,281	(\$2,997,445)	\$67,252	\$17,933	\$1,161,038	(\$98,440)	(\$42,377)	\$92,990	(\$3,687,694)	\$1,272,655	(\$3,136,458)
4	c.Retirements		-	-	-	(\$5,883,548)	-	-	-	-	-	-	(\$3,695,943)	-	(\$9,579,492)
5	d.Other		(\$7,130)	(\$13,379)	(\$19,475)	(\$258,268)	(\$15,562)	(\$8,969)	(\$19,681)	(\$1,013)	(\$9,253)	(\$352,426)	(\$43,226)	\$3,020,105	\$2,271,724
6															
7	Plant-In-Service/Depreciation Base	\$110,334,934	\$109,998,318	\$110,108,284	\$111,412,565	\$108,415,120	\$108,482,372	\$108,500,305	\$109,661,343	\$109,562,903	\$109,520,526	\$109,613,516	\$105,925,822	\$107,198,477	
8	Less: Accumulated Depreciation	\$13,619,444	\$14,034,100	\$14,442,105	\$14,847,141	\$9,125,907	\$9,524,897	\$9,930,642	\$10,327,893	\$10,745,803	\$11,155,215	\$11,221,565	\$7,894,390	\$11,321,880	
9	CWIP - Non Interest Bearing	\$962,770	\$1,438,455	\$2,044,500	\$1,880,507	\$511,118	\$970,446	\$1,254,852	\$517,788	\$1,886,623	\$2,050,734	\$4,292,547	\$130,673	\$1,243,367	
10															
11	Net Investment (Lines 7 - 8 + 9)	\$97,678,260	\$97,402,673	\$97,710,678	\$98,445,930	\$99,800,331	\$99,927,921	\$99,824,514	\$99,851,239	\$100,703,724	\$100,416,045	\$102,684,498	\$98,162,105	\$97,119,964	
12															
13	Average Net Investment		\$97,540,466	\$97,556,676	\$98,078,304	\$99,123,131	\$99,864,126	\$99,876,218	\$99,837,877	\$100,277,481	\$100,559,884	\$101,550,272	\$100,423,302	\$97,641,034	
14															
15	Return on Average Net Investment														
16	a.Equity Component grossed up for taxes ⁽¹⁾		\$540,673	\$540,762	\$543,654	\$549,445	\$553,553	\$553,620	\$548,725	\$551,141	\$552,693	\$558,136	\$551,942	\$536,651	\$6,580,994
17	b.Debt Component (Line 13 x debt rate x 1/12) ⁽²⁾		\$109,792	\$109,810	\$110,397	\$111,573	\$112,407	\$112,421	\$112,637	\$113,133	\$113,452	\$114,569	\$113,298	\$110,159	\$1,343,646
18															
19	Investment Expenses														
20	a.Depreciation		\$421,786	\$421,383	\$424,511	\$420,581	\$414,553	\$414,714	\$416,931	\$418,923	\$418,665	\$418,775	\$411,995	\$407,385	\$5,010,203
21	b.Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22	c.Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23															
24	Total System Recoverable Costs (Lines 16+17+20)		<u>\$1,072,250</u>	<u>\$1,071,956</u>	<u>\$1,078,562</u>	<u>\$1,081,599</u>	<u>\$1,080,512</u>	<u>\$1,080,755</u>	<u>\$1,078,293</u>	<u>\$1,083,197</u>	<u>\$1,084,810</u>	<u>\$1,091,480</u>	<u>\$1,077,235</u>	<u>\$1,054,194</u>	<u>\$12,934,844</u>
25															
26															
27															
28	⁽¹⁾ The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report														
29	and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.														
30	⁽²⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.														
31															
32	Totals may not add due to rounding														

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CEDAR BAY TRANSACTION
Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Line	Beginning of Period	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Regulatory Asset - Loss of PPA ⁽⁴⁾		\$278,839,317	\$274,191,995	\$269,544,673	\$264,897,351	\$260,250,029	\$255,602,707	\$250,955,385	\$246,308,063	\$241,660,741	\$237,013,419	\$232,366,097	\$227,718,775	
2															
3	Regulatory Asset - Loss of PPA Amort		\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$55,767,864
4															
5	Unamortized Regulatory Asset - Loss of PPA	\$278,839,317	\$274,191,995	\$269,544,673	\$264,897,351	\$260,250,029	\$255,602,707	\$250,955,385	\$246,308,063	\$241,660,741	\$237,013,419	\$232,366,097	\$227,718,775	\$223,071,453	
6															
7	Average Unamortized Regulatory Asset - Loss of PPA	-	\$276,515,656	\$271,868,334	\$267,221,012	\$262,573,690	\$257,926,368	\$253,279,046	\$248,631,724	\$243,984,402	\$239,337,080	\$234,689,758	\$230,042,436	\$225,395,114	
8															
9	Regulatory Asset - Income Tax Gross Up	\$178,030,026	\$175,111,501	\$172,192,976	\$169,274,451	\$166,355,926	\$163,437,401	\$160,518,876	\$157,600,351	\$154,681,826	\$151,763,301	\$148,844,776	\$145,926,251	\$143,007,726	
10															
11	Regulatory Asset Amortization - Income Tax Gross-Up	-	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$35,022,300
12															
13	Unamortized Regulatory Asset - Income Tax Gross Up	-	\$172,192,976	\$169,274,451	\$166,355,926	\$163,437,401	\$160,518,876	\$157,600,351	\$154,681,826	\$151,763,301	\$148,844,776	\$145,926,251	\$143,007,726	\$140,089,201	
14															
15	Return on Unamortized Regulatory Asset - Loss of PPA only														
16	a. Equity Component ⁽²⁾		\$1,156,886	\$1,137,443	\$1,117,999	\$1,098,556	\$1,079,112	\$1,059,669	\$1,031,424	\$1,012,145	\$992,866	\$973,587	\$954,308	\$935,029	\$12,549,024
17															
18	b. Equity Comp. grossed up for taxes ⁽²⁾		\$1,532,743	\$1,506,982	\$1,481,222	\$1,455,461	\$1,429,701	\$1,403,941	\$1,366,519	\$1,340,977	\$1,315,434	\$1,289,892	\$1,264,350	\$1,238,807	\$16,626,029
19															
20	c. Debt Component (Line 7 * debt rate / 12) ⁽³⁾		\$311,246	\$306,015	\$300,784	\$295,553	\$290,322	\$285,091	\$280,506	\$275,263	\$270,020	\$264,777	\$259,534	\$254,291	\$3,393,402
21															
22	Total Return Requirements (Line 18 + 20)		\$1,843,989	\$1,812,997	\$1,782,006	\$1,751,014	\$1,720,023	\$1,689,032	\$1,647,026	\$1,616,240	\$1,585,454	\$1,554,669	\$1,523,883	\$1,493,098	\$20,019,431
23	Total Recoverable Costs (Line 3 + 11 + 22)		\$9,409,836	\$9,378,844	\$9,347,853	\$9,316,861	\$9,285,870	\$9,254,879	\$9,212,873	\$9,182,087	\$9,151,301	\$9,120,516	\$9,089,730	\$9,058,945	\$110,809,595
24															

⁽¹⁾ The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report and reflects a 10.55% return on equity; the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

⁽²⁾ The Gross-up factors for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%.

⁽³⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

⁽⁴⁾ Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI, Order No. PSC-15-0401-AS-EI.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CEDAR BAY TRANSACTION
Regulatory Liability - Book/Tax Timing Difference Associated to Plant Asset

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Line	Beginning of Period	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Regulatory Liability - Book/Tax Timing Difference ⁽¹⁾		(\$3,652,117)	(\$3,591,249)	(\$3,530,381)	(\$3,469,513)	(\$3,408,645)	(\$3,347,777)	(\$3,286,909)	(\$3,226,041)	(\$3,165,173)	(\$3,104,305)	(\$3,043,437)	(\$2,982,569)	(\$39,808,116)
2															
3	Regulatory Liability Amortization		\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$730,416
4															
5	Unamortized Regulatory Liability - Book/Tax Timing Diff	(\$3,652,117)	(\$3,591,249)	(\$3,530,381)	(\$3,469,513)	(\$3,408,645)	(\$3,347,777)	(\$3,286,909)	(\$3,226,041)	(\$3,165,173)	(\$3,104,305)	(\$3,043,437)	(\$2,982,569)	(\$2,921,701)	(\$42,729,817)
6															
7	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		(\$3,621,683)	(\$3,560,815)	(\$3,499,947)	(\$3,439,079)	(\$3,378,211)	(\$3,317,343)	(\$3,256,475)	(\$3,195,607)	(\$3,134,739)	(\$3,073,871)	(\$3,013,003)	(\$2,952,135)	
8															
9	Return on Unamortized Regulatory Liability - Book/Tax Timing Difference		-	-	-	-	-	-	-	-	-	-	-	-	-
10															
11	a. Equity Component ⁽¹⁾		(\$15,152)	(\$14,898)	(\$14,643)	(\$14,388)	(\$14,134)	(\$13,879)	(\$13,509)	(\$13,257)	(\$13,004)	(\$12,752)	(\$12,499)	(\$12,247)	(\$164,362)
12															
13	b. Equity Comp. grossed up for taxes ⁽²⁾		(\$20,075)	(\$19,738)	(\$19,400)	(\$19,063)	(\$18,726)	(\$18,388)	(\$17,998)	(\$17,564)	(\$17,229)	(\$16,894)	(\$16,560)	(\$16,225)	(\$217,761)
14															
15	c. Debt Component (Line 7 * debt rate / 12) ⁽³⁾		(\$4,077)	(\$4,008)	(\$3,940)	(\$3,871)	(\$3,803)	(\$3,734)	(\$3,674)	(\$3,605)	(\$3,537)	(\$3,468)	(\$3,399)	(\$3,331)	(\$44,445)
16															
17	Total Return Requirements (Line 13 + 15)		(\$24,152)	(\$23,746)	(\$23,340)	(\$22,934)	(\$22,528)	(\$22,122)	(\$21,572)	(\$21,169)	(\$20,766)	(\$20,362)	(\$19,959)	(\$19,556)	(\$262,206)
18	Total Recoverable Costs (Line 3 - 17)		(\$85,020)	(\$84,614)	(\$84,208)	(\$83,802)	(\$83,396)	(\$82,990)	(\$82,440)	(\$82,037)	(\$81,634)	(\$81,230)	(\$80,827)	(\$80,424)	(\$992,622)
19															
20															

⁽¹⁾ The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report and reflects a 10.55% return on equity, the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

⁽²⁾ The Gross-up factor for taxes is 0.75478, which reflect he Federal Income Tax Rate of 21%.

⁽³⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

⁽⁴⁾ Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI, Order No. PSC-15-0401-AS-EI.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INDIANTOWN TRANSACTION
Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Line	Beginning of Period	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Regulatory Asset - Loss of PPA ⁽¹⁾	-	\$300,999,999	\$296,819,444	\$292,638,888	\$288,458,333	\$284,277,777	\$280,097,221	\$275,916,666	\$271,736,110	\$267,555,555	\$263,374,999	\$259,194,444	\$255,013,888	\$3,336,083,324
2															
3	Regulatory Asset - Loss of PPA Amort	-	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$50,166,667
4															
5	Unamortized Regulatory Asset - Loss of PPA	\$300,999,999	\$296,819,444	\$292,638,888	\$288,458,333	\$284,277,777	\$280,097,221	\$275,916,666	\$271,736,110	\$267,555,555	\$263,374,999	\$259,194,444	\$255,013,888	\$250,833,333	\$3,586,916,657
6															
7	Average Unamortized Regulatory Asset - Loss of PPA		\$298,909,722	\$294,729,166	\$290,548,610	\$286,368,055	\$282,187,499	\$278,006,944	\$273,826,388	\$269,645,833	\$265,465,277	\$261,284,721	\$257,104,166	\$252,923,610	
8															
9	Return on Unamortized Regulatory Asset - Loss of PPA only														
10	a. Equity Component ⁽²⁾		\$1,250,578	\$1,233,088	\$1,215,597	\$1,198,107	\$1,180,616	\$1,163,125	\$1,135,941	\$1,118,599	\$1,101,256	\$1,083,914	\$1,066,571	\$1,049,228	\$13,796,621
11															
12	b. Equity Comp. grossed up for taxes ⁽²⁾		\$1,656,874	\$1,633,701	\$1,610,528	\$1,587,355	\$1,564,182	\$1,541,009	\$1,504,993	\$1,482,016	\$1,459,039	\$1,436,062	\$1,413,085	\$1,390,108	\$18,278,953
13															
14	c. Debt Component (Line 7 * debt rate / 12) ⁽³⁾		\$336,453	\$331,747	\$327,042	\$322,336	\$317,630	\$312,925	\$308,931	\$304,214	\$299,498	\$294,781	\$290,065	\$285,348	\$3,730,970
15															
16	Total Return Requirements (Line 18 + 20)		\$1,993,327	\$1,965,448	\$1,937,570	\$1,909,691	\$1,881,812	\$1,853,933	\$1,813,924	\$1,786,231	\$1,758,537	\$1,730,844	\$1,703,150	\$1,675,457	\$22,009,923
17	Total Recoverable Costs (Line 3 + 11 + 22)		\$6,173,883	\$6,146,004	\$6,118,125	\$6,090,246	\$6,062,368	\$6,034,489	\$5,994,480	\$5,966,786	\$5,939,093	\$5,911,399	\$5,883,706	\$5,856,012	\$72,176,590
18															

⁽¹⁾ The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report and reflects a 10.55% return on equity, the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

⁽²⁾ The Gross-up factor for taxes is 0.75478, which reflect he Federal Income Tax Rate of 21%.

⁽³⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

⁽⁴⁾ Recovery of the Indiantown Transaction is based on the settlement agreement approved by the FPSC in Docket No. 20160154-EI, Order No. PSC-2016-0506-FOF-EI.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SJRPP TRANSACTION
Regulatory Assets and Liabilities Related to the SJRPP Transaction

FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

Line No.	Line	Beginning Balance	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Regulatory Asset - SJRPP Transaction Shutdown Payment ⁽¹⁾		\$43,234,783	\$41,269,566	\$39,304,348	\$37,339,131	\$35,373,913	\$33,408,696	\$31,443,479	\$29,478,261	\$27,513,044	\$25,547,826	\$23,582,609	\$21,617,392	
2	Regulatory Asset - SJRPP Transaction Shutdown Payment Amortiz.		\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$23,582,609
3	Unamortized Regulatory Asset - SJRPP Transaction Shutdown Pay	\$43,234,783	\$41,269,566	\$39,304,348	\$37,339,131	\$35,373,913	\$33,408,696	\$31,443,479	\$29,478,261	\$27,513,044	\$25,547,826	\$23,582,609	\$21,617,392	\$19,652,174	
4															
5	Other regulatory liability - SJRPP Suspension Liability		(\$4,736,980)	(\$4,521,663)	(\$4,306,346)	(\$4,091,028)	(\$3,875,711)	(\$3,660,394)	(\$3,445,076)	(\$3,229,759)	(\$3,014,442)	(\$2,799,125)	(\$2,583,807)	(\$2,368,490)	(\$42,632,821)
6	Other regulatory liability - SJRPP Suspension Liability Amortization		(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$2,583,807)
7	Unamortized Regulatory Liability - SJRPP Suspension Liability	(\$4,736,980)	(\$4,521,663)	(\$4,306,346)	(\$4,091,028)	(\$3,875,711)	(\$3,660,394)	(\$3,445,076)	(\$3,229,759)	(\$3,014,442)	(\$2,799,125)	(\$2,583,807)	(\$2,368,490)	(\$2,153,173)	
8															
9	Average Net Unamortized Regulatory Asset/Liab (Lines 3 + 7)		\$37,622,853	\$35,872,953	\$34,123,053	\$32,373,152	\$30,623,252	\$28,873,352	\$27,123,452	\$25,373,552	\$23,623,652	\$21,873,752	\$20,123,852	\$18,373,951	
10															
11	Equity Component		\$157,406	\$150,085	\$142,764	\$135,443	\$128,122	\$120,800	\$112,519	\$105,260	\$98,000	\$90,741	\$83,482	\$76,223	\$1,400,845
12	Equity Comp. grossed up for taxes ⁽¹⁾		\$208,546	\$198,846	\$189,146	\$179,446	\$169,746	\$160,047	\$149,075	\$139,457	\$129,839	\$120,222	\$110,604	\$100,986	\$1,855,960
13	Debt Component (Line 9 x debt rate / 12) ⁽²⁾		\$42,348	\$40,379	\$38,409	\$36,439	\$34,470	\$32,500	\$30,601	\$28,626	\$26,652	\$24,678	\$22,704	\$20,729	\$378,535
14															
15	Total Return Requirements (Line 12 + 13)		\$250,894	\$239,224	\$227,555	\$215,886	\$204,216	\$192,547	\$179,675	\$168,083	\$156,492	\$144,900	\$133,308	\$121,716	\$2,234,495
16															
17	Other SJRPP Transaction Items ⁽⁴⁾														
18	SJRPP Deferred Interest Amortization (Refund)		(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$3,230,181)
19	SJRPP Article 8 PPA Dismantlement Accrual Amortization (Refund)		(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$10,414,774)
20															
21	Total Recoverable Expenses (Lines 2 + 6 + 15 + 18 + 19)		\$863,715	\$852,045	\$840,376	\$828,706	\$817,037	\$805,367	\$792,496	\$780,904	\$769,312	\$757,720	\$746,128	\$734,536	\$9,588,341

⁽¹⁾ The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

⁽²⁾ The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

⁽³⁾ Recovery of the SJRPP Transaction over a 46 month period is based on the settlement agreement approved by the FPSC in Docket No. 20170123-EI Order No. PSC-2017-0415-AS-EI.

⁽⁴⁾ The total amount of SJRPP Deferred Interest and Article 8 PPA Dismantlement Accrual to refund is \$12.4M and \$39.9M, respectively. The unamortized balances for these regulatory liabilities are a reflected in rate base.

Totals may not add due to rounding

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

For the Month of Dec-20

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

QF = Qualifying Facility

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
ICL													0
BS-NEG '91	167,174	119,175	119,175	119,175	119,175	119,175	119,175	119,175	119,175	119,175	119,175	119,175	1,478,099
Total	167,174	119,175	119,175	119,175	119,175	119,175	119,175	119,175	119,175	119,175	119,175	119,175	1,478,099

Notes:

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

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

For the Month of Dec-20

<u>Contract</u>	<u>Counterparty</u>	<u>Identification</u>	<u>Contract Start Date</u>	<u>Contract End Date</u>
1	Solid Waste Authority - 40 MW	Other Entity	January, 2012	March 31, 2032
2	Solid Waste Authority - 70 MW	Other Entity	July, 2015	May 31, 2034
3	Orlando Utilities Commission OP-CAP	Other Entity	December 17, 2018	December 31, 2020

2020 Capacity in MW

<u>Contract</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>
1	40	40	40	40	40	40	40	40	40	40	40	40
2	70	70	70	70	70	70	70	70	70	70	70	70
3	70	70	70	70	100	100	100	100	100	80	80	80
Total	180	180	180	180	210	210	210	210	210	190	190	190

2020 Capacity in Dollars

	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>
Total	2,083,820	2,083,820	2,083,820	2,083,820	2,412,200	2,145,800	2,456,600	2,412,200	2,412,200	2,192,619	2,193,280	2,193,280

Year-to-date Short Term Capacity Payments	26,753,459 ⁽¹⁾
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(1) Total capacity costs do not include payments for the Solid Waste Authority - 70 MW unit. Capacity costs for this unit were recovered through the Energy Conservation Cost Recovery Clause in 2014, consistent with Commission Order No. PSC-11-0293-FOF-EU issued in Docket No. 110018-EU on July 6, 2011.

<u>Contract</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>
1												
2												
3												

<u>True ups</u>												
1												
2												
3												

**FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES**

Equity @ 10.55%	CAPITAL STRUCTURE AND COST RATES PER MAY 2019 EARNINGS SURVEILLANCE REPORT				
	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	10,490,880,245	28.119%	4.44%	1.25%	1.25%
SHORT_TERM_DEBT	669,988,433	1.796%	3.62%	0.06%	0.06%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	403,097,747	1.080%	2.11%	0.02%	0.02%
COMMON_EQUITY	17,554,936,062	47.053%	10.55%	4.96%	6.65%
DEFERRED_INCOME_TAX	7,870,776,333	21.096%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	319,453,350	0.856%	8.26%	0.07%	0.09%
TOTAL	\$37,309,132,171	100.00%		6.37%	8.08%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)					
	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	\$10,490,880,245	37.41%	4.441%	1.661%	1.661%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	17,554,936,062	62.59%	10.550%	6.604%	8.846%
TOTAL	\$28,045,816,308	100.00%		8.265%	10.507%
RATIO					

DEBT COMPONENTS:

LONG TERM DEBT	1.2488%
SHORT TERM DEBT	0.0649%
CUSTOMER DEPOSITS	0.0228%
TAX CREDITS -WEIGHTED	0.0142%
TOTAL DEBT	1.3507%

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	4.9641%
TAX CREDITS -WEIGHTED	0.0565%
TOTAL EQUITY	5.0206%
TOTAL	6.3713%
PRE-TAX EQUITY	6.7251%
PRE-TAX TOTAL	8.0758%

Note:

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

**FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES**

**CAPITAL STRUCTURE AND COST RATES PER
MAY 2020 EARNINGS SURVEILLANCE REPORT**

Equity @ 10.55%

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	12,539,092,665	30.643%	4.17%	1.28%	1.28%
SHORT_TERM_DEBT	462,827,285	1.131%	3.16%	0.04%	0.04%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	420,293,246	1.027%	2.12%	0.02%	0.02%
COMMON_EQUITY	19,050,189,760	46.554%	10.55%	4.91%	6.51%
DEFERRED_INCOME_TAX	8,019,547,167	19.598%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	428,551,760	1.047%	8.02%	0.08%	0.11%
TOTAL	\$40,920,501,883	100.00%		6.33%	7.95%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)					
	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	\$12,539,092,665	39.69%	4.174%	1.657%	1.657%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	19,050,189,760	60.31%	10.550%	6.362%	8.429%
TOTAL	\$31,589,282,425	100.00%		8.019%	10.086%
RATIO					

DEBT COMPONENTS:

LONG TERM DEBT	1.2789%
SHORT TERM DEBT	0.0357%
CUSTOMER DEPOSITS	0.0218%
TAX CREDITS -WEIGHTED	0.0174%
TOTAL DEBT	1.3538%

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	4.9115%
TAX CREDITS -WEIGHTED	0.0666%
TOTAL EQUITY	4.9781%
TOTAL	6.3319%
PRE-TAX EQUITY	6.5954%
PRE-TAX TOTAL	7.9492%

Note:

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

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	FCR - E1-B	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
1	Fuel Costs & Net Power Transactions													
2	Fuel Cost of System Net Generation (E3)	196,093,006	236,914,902	232,667,765	225,565,917	278,330,509	282,924,116	300,187,942	310,518,070	297,631,438	276,982,492	234,422,308	238,554,425	3,110,792,892
3	Rail Car Lease (Cedar Bay/Indiantown)	135,560	145,146	146,169	131,899	89,641	275,055	164,666	165,557	165,557	164,666	165,557	164,666	1,914,139
4	Fuel Cost of Stratified Sales	(2,029,516)	(2,426,951)	(3,092,458)	(2,549,736)	(2,702,691)	(3,957,871)	(2,007,496)	(2,110,086)	(2,097,265)	(1,672,301)	(1,374,606)	(951,556)	(26,972,532)
5	Fuel Cost of Power Sold (E6)	(3,036,111)	(4,808,540)	(3,570,186)	(5,100,462)	(4,246,828)	(6,427,033)	(3,742,753)	(4,076,180)	(3,982,556)	(3,590,407)	(4,882,444)	(4,845,887)	(52,309,388)
6	Gains from Off-System Sales (E6)	(1,039,604)	(4,412,077)	(1,385,402)	(1,948,740)	(1,689,592)	(2,498,511)	(1,458,759)	(1,410,502)	(1,366,865)	(1,368,411)	(1,705,853)	(1,636,460)	(21,920,777)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	2,653,162	3,079,694	3,466,300	2,196,670	2,839,335	2,849,346	2,777,606	2,758,335	2,353,189	2,459,689	2,631,543	2,859,802	32,924,671
8	Energy Payments to Qualifying Facilities (Per E8)	148,230	860,916	247,650	433,716	377,695	460,548	543,844	474,917	628,902	531,444	573,623	613,145	5,894,630
9	Energy Cost of Economy Purchases (Per E9)	0	335,359	229,632	608,471	9,533,861	5,356,987	1,320,600	492,900	1,436,400	1,193,500	0	0	20,507,711
10		192,924,727	229,688,448	228,709,470	219,337,736	282,531,932	278,982,637	297,785,649	306,813,011	294,768,800	274,700,673	229,830,128	234,758,135	3,070,831,346
11	Incremental Optimization Costs ⁽¹⁾													
12	Incremental Personnel, Software, and Hardware Costs	38,881	37,697	43,269	41,219	39,477	43,655	38,141	39,781	34,861	39,781	38,141	36,501	471,405
13	Var. Power Plant O&M Costs Attributable to Off-Sys Sales (E6)	111,151	162,731	114,110	156,034	110,209	167,747	92,287	95,713	89,115	89,466	141,765	133,595	1,463,924
14	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	0	(3,312)	(3,963)	(8,317)	(129,850)	(79,020)	(28,613)	(10,680)	(32,760)	(28,210)	(0)	(0)	(324,724)
15		150,032	197,117	153,416	188,936	19,836	132,382	101,815	124,814	91,216	101,037	179,906	170,096	1,610,605
16	Adjustments to Fuel Cost													
17	Reactive and Voltage Control Fuel Revenues	(134,118)	(107,079)	(84,053)	(5,237)	(46,309)	(76,006)	0	0	0	0	0	0	(452,802)
18	Other O&M Expense	171	0	0	(4,624)	31,173	468,074	0	0	0	0	0	0	494,794
19	Inventory Adjustments	(12,731)	35,434	(93,166)	57,883	35,889	16,109	0	0	0	0	0	0	39,418
20		(146,678)	(71,646)	(177,219)	48,022	20,752	408,177	0	0	0	0	0	0	81,409
21	Adjusted Total Fuel Costs & Net Power Transactions	192,928,081	229,813,920	228,685,667	219,574,694	282,572,520	279,523,197	297,887,465	306,937,825	294,860,016	274,801,710	230,010,034	234,928,231	3,072,523,360
22	kWh Sales													
23	Retail kWh Sales	7,920,264,452	7,672,369,137	8,050,207,476	8,597,508,595	9,741,408,902	10,281,014,783	10,845,071,472	11,150,324,537	10,846,656,951	9,823,896,585	8,733,550,051	8,111,829,907	111,774,102,848
24	Sale for Resale	396,711,147	402,529,066	400,986,769	442,738,116	460,603,206	532,167,836	518,564,950	549,520,507	551,702,817	494,851,181	492,994,344	409,204,283	5,652,574,222
25	Retail % of Total kWh Sales	95.23010%	95.01506%	95.25527%	95.10259%	95.48517%	95.07853%	95.43663%	95.30318%	95.15981%	95.20435%	94.65678%	95.19772%	
26	Revenues Applicable to Period													
27	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	189,607,980	182,758,194	192,250,967	206,929,145	275,856,968	292,572,663	306,586,171	315,215,562	306,630,992	277,717,933	246,894,239	229,318,440	3,022,339,254
28	Prior Period True-Up (Collected)/Refunded This Period ⁽²⁾	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(20,669,910)
29	Midcourse Correction - Prior Year Final True-Up (Collected)/Refunded this Period	0	0	0	0	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(72,891,803)
30	GPIF, Net of Revenue Taxes ⁽³⁾	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(8,119,831)
31	Asset Optimization, Net of Revenue Taxes ⁽⁴⁾	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(8,697,268)
32	Solar Together Credit, Net of Revenue Taxes ⁽⁵⁾	(2,233,951)	(3,807,644)	(3,861,993)	(5,607,909)	(7,442,029)	(9,161,666)	(10,614,961)	(10,061,567)	(9,417,233)	(9,640,037)	(8,567,962)	(7,678,134)	(88,095,086)
33		184,250,112	175,826,632	185,265,056	198,197,318	256,179,546	271,175,604	283,735,817	292,918,603	284,978,366	255,842,504	226,090,884	209,404,913	2,823,865,356
34	True-Up Calculation													
35	Adjusted Total Fuel Costs & Net Power Transactions	192,928,081	229,813,920	228,685,667	219,574,694	282,572,520	279,523,197	297,887,465	306,937,825	294,860,016	274,801,710	230,010,034	234,928,231	3,072,523,360
36	Jurisdictional Sales % of Total kWh Sales	95.23010%	95.01506%	95.25527%	95.10259%	95.48517%	95.07853%	95.43663%	95.30318%	95.15981%	95.20435%	94.65678%	95.19772%	
37	Retail Total Fuel Costs & Net Power Transactions	183,975,472	218,715,067	218,191,528	209,162,852	270,256,268	266,201,340	284,758,862	293,000,073	281,047,273	262,051,198	218,076,282	224,012,205	2,929,448,421
38	True-Up Provision for the Month-Over/(Under) Recovery	274,640	(42,888,435)	(32,926,472)	(10,965,534)	(14,076,722)	4,974,264	(1,023,045)	(81,470)	3,931,093	(6,208,694)	8,014,602	(14,607,292)	(105,583,064)
39	Interest Provision for the Month	(6,557)	(7,944)	(12,362)	(12,644)	(8,013)	(8,428)	(10,693)	(10,008)	(9,158)	(8,512)	(7,729)	(7,227)	(109,276)
40	True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	(20,669,910)	(18,679,334)	(59,853,221)	(91,069,563)	(100,325,247)	(112,687,490)	(105,999,162)	(105,310,408)	(103,679,394)	(98,034,966)	(102,529,679)	(92,800,314)	(20,669,910)
41	Deferred True-up Beginning of Period - Over/(Under) Recovery ⁽²⁾	(72,891,803)	(72,891,803)	(72,891,803)	(72,891,803)	(72,891,803)	(63,780,327)	(54,668,852)	(45,557,377)	(36,445,901)	(27,334,426)	(18,222,951)	(9,111,475)	(72,891,803)
42	Midcourse Correction - Prior Year Final True-Up (Collected)/Refunded this Period					9,111,475	9,111,475	9,111,475	9,111,475	9,111,475	9,111,475	9,111,475	9,111,475	72,891,803
43	Prior Period True Up Collected/(Refunded) This Period	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	20,669,910
44	End of Period Net True-up Amount Over/(Under) Recovery	(91,571,137)	(132,745,023)	(163,961,365)	(173,217,050)	(176,467,817)	(160,668,014)	(150,867,784)	(140,125,295)	(125,369,392)	(120,752,630)	(101,911,789)	(105,692,340)	(105,692,340)

⁽¹⁾ Amounts reflected in this section are in accordance with FPL's Stipulation and Settlement approved by the Commission in Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI

⁽²⁾ Prior Period 2020 Actual/Estimated True-up

⁽³⁾ Generating Performance Incentive Factor is (($\$8,125,681/12$) x 99.9280%) - See Order No. PSC-2020-0439-FOF-EI

⁽⁴⁾ Jurisdictionalized Asset Optimization - FPL Portion is (($\$8,703,535/12$) x 99.9280%) - See Order No. PSC-2020-0439-FOF-EI

⁽⁵⁾ Approved in Order No. PSC-2020-0084-S-EI issued in Docket No. 20190061-EI on March 20, 2020

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL/ESTIMATED

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	FCR - E1-B Variance	2021			
		Current	Prior	Difference	% Difference
1	Fuel Costs & Net Power Transactions				
2	Fuel Cost of System Net Generation (E3)	3,110,792,892	2,978,097,287	132,695,605	4.5%
3	Rail Car Lease (Cedar Bay/Indiantown)	1,914,139	1,950,450	(36,312)	(1.9%)
4	Fuel Cost of Stratified Sales	(26,972,532)	(31,867,987)	4,895,454	(15.4%)
5	Fuel Cost of Power Sold (Per E6)	(52,309,388)	(53,674,975)	1,365,588	(2.5%)
6	Gains from Off-System Sales (Per E6)	(21,920,777)	(19,677,688)	(2,243,089)	11.4%
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	32,924,671	31,202,951	1,721,720	5.5%
8	Energy Payments to Qualifying Facilities (E8)	5,894,630	6,238,945	(344,315)	(5.5%)
9	Energy Cost of Economy Purchases (E9)	20,507,711	9,950,429	10,557,282	106.1%
10	Total Fuel Costs & Net Power Transactions	3,070,831,346	2,922,219,412	148,611,934	5.1%
11					
12	Incremental Optimization Costs ⁽¹⁾				
13	Incremental Personnel, Software, and Hardware Costs	471,405	451,874	19,531	4.3%
14	Var. Power Plant O&M Costs Attributable to Off-Sys Sales (E6)	1,463,924	1,479,321	(15,397)	(1.0%)
15	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	(324,724)	(227,269)	(97,456)	42.9%
16	Total Incremental Optimization Costs	1,610,605	1,703,926	(93,322)	(5.5%)
17					
18	Adjustments to Fuel Cost				
19	Reactive and Voltage Control Fuel Revenues	(452,802)	(134,118)	(318,684)	237.6%
20	Other O&M Expense	494,794	573,131	(78,337)	(13.7%)
21	Inventory Adjustments	39,418	(12,731)	52,149	(409.6%)
22	Total Adjustments to Fuel Cost	81,409	426,282	(344,873)	(80.9%)
23					
24	Adjusted Total Fuel Costs & Net Power Transactions	3,072,523,360	2,924,349,620	148,173,739	5.1%
25					
26	kWh Sales				
27	Retail kWh Sales	111,774,102,848	110,457,860,306	1,316,242,542	1.2%
28	Sale for Resale	5,652,574,222	5,517,927,788	134,646,434	2.4%
29	Total Sales	117,426,677,070	115,975,788,094	1,450,888,976	1.3%
30					
31	Retail % of Total kWh Sales	95.1863%	95.2422%		
32					
33	Revenues Applicable to Period				
34	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	3,022,339,254	2,996,378,148	25,961,106	0.9%
35	Prior Period True-Up (Collected)/Refunded This Period	(20,669,910)	(20,669,910)	0	N/A
36	Midcourse Correction - Prior Year Final True-Up (Collected)/Refunded this Period ⁽²⁾	(72,891,803)	(72,891,803)	0	N/A
37	GPIF, Net of Revenue Taxes ⁽³⁾	(8,119,831)	(8,119,831)	0	N/A
38	Asset Optimization, Net of Revenue Taxes ⁽⁴⁾	(8,697,268)	(8,697,268)	(0)	0.0%
39	SolarTogether Credit, Net of Revenue Taxes ⁽⁵⁾	(88,095,086)	(96,025,708)	7,930,623	(8.3%)
40		2,823,865,356	2,789,973,628	33,891,728	1.2%
41	True-Up Calculation				
42	Adjusted Total Fuel Costs & Net Power Transactions	3,072,523,360	2,924,349,620	148,173,739	5.1%
43	Jurisdictional Sales % of Total kWh Sales	95.1863%	N/A		
44	Retail Total Fuel Costs & Net Power Transactions	2,929,448,421	2,789,973,628	139,474,792	5.0%
45	True-Up Provision for the Month-Over/(Under) Recovery	(105,583,064)	0	(105,583,064)	N/A
46	Interest Provision for the Month	(109,276)	0	(109,276)	N/A
47	True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	(20,669,910)	(20,669,910)	0	N/A
48	Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,891,803)	(72,891,803)	0	N/A
49	Midcourse Correction - Prior Year Final True-Up Collected/(Refunded) this Period	72,891,803	72,891,803	0	N/A
50	Prior Period True Up Collected/(Refunded) This Period	20,669,910	20,669,910	0	N/A
51	End of Period Net True-up Amount Over/(Under) Recovery	(105,692,340)	0	(105,692,340)	N/A

⁽¹⁾ Amounts reflected in this section are in accordance with FPL's Stipulation and Settlement approved by the Commission in Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI

⁽²⁾ Prior Period 2020 Actual/Estimated True-up

⁽³⁾ Generating Performance Incentive Factor is $((\$8,125,681/12) \times 99.9280\%)$ - See Order No. PSC-2020-0439-FOF-EI

⁽⁴⁾ Jurisdictionalized Asset Optimization - FPL Portion is $((\$8,703,535/12) \times 99.9280\%)$ - See Order No. PSC-2020-0439-FOF-EI

⁽⁵⁾ Approved in Order No. PSC-2020-0084-S-EI issued in Docket No. 20190061-EI on March 20, 2020

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE E3

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	FCR - E3	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Fuel Cost of System Net Generation (\$)													
2	Heavy Oil	0	395,439	967,310	2,140,452	1,449,516	436,191	902,253	1,905,102	2,697,063	1,632,595	0	0	12,525,920
3	Light Oil	779,832	3,582,725	490,603	333,790	1,242,013	1,260,320	310,544	437,218	1,468,413	707,422	0	0	10,612,881
4	Coal	1,830,141	6,128,978	5,388,631	2,328,385	10,707,125	6,379,437	7,380,430	7,533,974	7,169,634	6,509,361	5,975,683	6,234,535	73,566,315
5	Gas	179,842,136	214,300,687	212,154,964	210,537,024	252,830,400	261,102,535	278,184,905	287,591,402	276,014,871	257,188,857	216,029,029	218,784,816	2,864,561,626
6	Nuclear	13,640,896	12,507,074	13,666,257	10,226,267	12,101,456	13,745,634	13,409,810	13,050,373	10,281,457	10,944,257	12,417,597	13,535,074	149,526,153
7	Subtotal Fuel Cost of System Net Generation (\$)	196,093,006	236,914,903	232,667,766	225,565,918	278,330,509	282,924,116	300,187,942	310,518,070	297,631,438	276,982,492	234,422,308	238,554,425	3,110,792,894
8														
9	System Net Generation (MWh)													
10	Heavy Oil	(1,846)	2,971	7,493	16,491	10,934	3,139	6,366	14,192	19,943	11,842	0	0	91,526
11	Light Oil	5,374	35,269	3,724	2,287	8,988	10,492	1,483	2,257	7,338	3,807	0	0	81,020
12	Coal	152,748	204,183	167,673	179,481	179,098	192,054	248,246	259,455	250,325	225,336	206,613	216,006	2,481,218
13	Gas	5,570,003	5,787,680	6,441,824	7,170,402	8,253,106	8,285,020	8,771,631	9,027,530	8,776,252	7,867,597	6,155,921	5,879,248	87,986,214
14	Nuclear	2,600,121	2,370,891	2,560,807	2,075,177	2,233,285	2,570,483	2,540,294	2,461,676	1,868,711	2,070,152	2,397,888	2,602,438	28,351,923
15	Solar ⁽²⁾	341,110	350,305	459,275	530,409	628,873	483,554	618,996	590,755	541,991	548,914	479,376	431,901	6,005,459
16	Subtotal System Net Generation (MWh)	8,667,511	8,751,299	9,640,796	9,974,247	11,314,284	11,544,743	12,187,016	12,355,865	11,464,561	10,727,648	9,239,798	9,129,592	124,997,360
17														
18	Units of Fuel Burned (Uniq⁽¹⁾)													
19	Heavy Oil		5,418	13,253	29,327	19,859	5,976	11,936	25,203	35,680	21,598			168,248
20	Light Oil	7,907	40,985	4,854	3,615	13,485	12,510	4,066	5,725	18,075	7,472			118,694
21	Coal	49,863	134,559	116,324	47,707	122,185	132,975	160,934	167,453	161,571	147,584	135,827	141,762	1,518,744
22	Gas	39,204,020	40,987,349	46,132,439	50,753,474	58,604,478	58,426,257	60,083,906	62,145,548	60,028,536	53,579,630	41,344,978	39,832,821	611,123,436
23	Nuclear	27,649,786	25,358,591	27,420,987	22,533,770	24,363,299	27,788,854	27,046,432	26,221,278	19,985,311	21,966,592	24,903,353	27,047,123	302,285,375
24														
25														
26	BTU Burned (MMBTU)													
27	Heavy Oil	0	34,290	83,879	185,608	125,688	37,822	76,390	161,297	228,349	138,225	0	0	1,071,548
28	Light Oil	45,608	239,929	29,259	20,966	77,934	73,400	23,706	33,376	105,375	43,561	0	0	693,115
29	Coal	653,395	2,253,298	1,948,721	797,380	3,893,973	2,255,665	2,735,886	2,846,705	2,746,710	2,508,923	2,309,051	2,409,946	27,359,653
30	Gas	39,204,052	40,987,540	46,132,513	50,753,622	58,604,478	58,426,451	60,083,906	62,145,548	60,028,536	53,579,630	41,344,978	39,832,821	611,124,075
31	Nuclear	27,649,786	25,358,591	27,420,987	22,533,770	24,363,299	27,788,854	27,046,432	26,221,278	19,985,311	21,966,592	24,903,353	27,047,123	302,285,375
32	Subtotal BTU Burned (MMBTU)	67,552,841	68,873,648	75,615,360	74,291,346	87,065,372	88,582,192	89,966,320	91,408,204	83,094,281	78,236,931	68,557,382	69,289,890	942,533,766
33														
34	Fuel Cost per Unit (\$/Unit)													
35	Heavy Oil		72.9870	72.9871	72.9869	72.9904	72.9904	75.5913	75.5913	75.5913	75.5913			74.4490
36	Light Oil	98.6255	87.4155	101.0719	92.3346	92.1033	100.7450	76.3717	76.3716	81.2418	94.6781			89.4141
37	Coal	36.7032	45.5485	46.3242	48.8063	87.6305	47.9747	45.8598	44.9915	44.3745	44.1062	43.9950	43.9790	48.4389
38	Gas	4.5873	5.2285	4.5988	4.1482	4.3142	4.4689	4.6299	4.6277	4.5981	4.8001	5.2250	5.4926	4.6874
39	Nuclear	0.4933	0.4932	0.4984	0.4538	0.4967	0.4946	0.4958	0.4977	0.5145	0.4982	0.4986	0.5004	0.4947
40														
41	Generation Mix (%)													
42	Heavy Oil	(0.02%)	0.03%	0.08%	0.17%	0.10%	0.03%	0.05%	0.11%	0.17%	0.11%	0%	0%	0.07%
43	Light Oil	0.06%	0.40%	0.04%	0.02%	0.08%	0.09%	0.01%	0.02%	0.06%	0.04%	0%	0%	0.06%
44	Coal	1.76%	2.33%	1.74%	1.80%	1.58%	1.66%	2.04%	2.10%	2.18%	2.10%	2.24%	2.37%	1.99%
45	Gas	64.26%	66.14%	66.82%	71.89%	72.94%	71.76%	71.98%	73.06%	76.55%	73.34%	66.62%	64.40%	70.39%
46	Nuclear	30.00%	27.09%	26.56%	20.81%	19.74%	22.27%	20.84%	19.92%	16.30%	19.30%	25.95%	28.51%	22.68%
47	Solar	3.94%	4.00%	4.76%	5.32%	5.56%	4.19%	5.08%	4.78%	4.73%	5.12%	5.19%	4.73%	4.80%
48														

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE E3

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	FCR - E3	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Fuel Cost per MMBTU (\$/MMBTU)													
2	Heavy Oil		11.5322	11.5322	11.5321	11.5327	11.5327	11.8111	11.8111	11.8111	11.8111			11.6896
3	Light Oil	17.0985	14.9324	16.7674	15.9201	15.9367	17.1707	13.0998	13.0998	13.9351	16.2398			15.3119
4	Coal	2.8010	2.7200	2.7652	2.9200	2.7497	2.8282	2.6976	2.6466	2.6103	2.5945	2.5879	2.5870	2.6889
5	Gas	4.5873	5.2284	4.5988	4.1482	4.3142	4.4689	4.6299	4.6277	4.5981	4.8001	5.2250	5.4926	4.6874
6	Nuclear	0.4933	0.4932	0.4984	0.4538	0.4967	0.4946	0.4958	0.4977	0.5145	0.4982	0.4986	0.5004	0.4947
7														
8	BTU Burned per KWH (BTU/KWH)													
9	Heavy Oil	0	11,540	11,194	11,255	11,496	12,048	12,000	11,365	11,450	11,672	0	0	11,708
10	Light Oil	8,486	6,803	7,856	9,167	8,671	6,995	15,985	14,788	14,360	11,442	0	0	8,555
11	Coal	4,278	11,036	11,622	4,443	21,742	11,745	11,021	10,972	10,973	11,134	11,176	11,157	11,027
12	Gas	7,038	7,082	7,161	7,078	7,101	7,052	6,850	6,884	6,840	6,810	6,716	6,775	6,946
13	Nuclear	10,634	10,696	10,708	10,859	10,909	10,811	10,647	10,652	10,695	10,611	10,386	10,393	10,662
14														
15	Generated Fuel Cost per KWH (cents/KWH)													
16	Heavy Oil		13.3086	12.9095	12.9794	13.2575	13.8947	14.1732	13.4236	13.5240	13.7860			13.6856
17	Light Oil	14.5104	10.1583	13.1728	14.5941	13.8182	12.0117	20.9402	19.3717	20.0111	18.5818			13.0990
18	Coal	1.1981	3.0017	3.2138	1.2973	5.9784	3.3217	2.9730	2.9038	2.8641	2.8887	2.8922	2.8863	2.9649
19	Gas	3.2288	3.7027	3.2934	2.9362	3.0635	3.1515	3.1714	3.1857	3.1450	3.2690	3.5093	3.7213	3.2557
20	Nuclear	0.5246	0.5275	0.5337	0.4928	0.5419	0.5347	0.5279	0.5301	0.5502	0.5287	0.5179	0.5201	0.5274
21	Subtotal Generated Fuel Cost per KWH (cents/KWH)	2.2624	2.7072	2.4134	2.2615	2.4600	2.4507	2.4632	2.5131	2.5961	2.5819	2.5371	2.6130	2.4887

⁽¹⁾ Fuel Units: Heavy Oil - BBLs, Light Oil - BBLs, Coal - TONS, Gas - MCF, Nuclear - MMBTU

⁽²⁾ Actuals do not include Martin 8 solar

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Jul - 2021</u>												
2	<u>Babcock Preserve ST Solar</u>												
3	Solar		15,420					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	15,420	27.8%	N/A	27.8%	N/A						
5	<u>Babcock PV Solar</u>												
6	Solar		14,422					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,422	26.0%	N/A	26.0%	N/A						
8	<u>Barefoot PV Solar</u>												
9	Solar		15,838					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,838	28.6%	N/A	28.6%	N/A						
11	<u>Blue Cypress PV Solar</u>												
12	Solar		16,150					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,150	29.1%	N/A	29.1%	N/A						
14	<u>Blue Heron ST Solar</u>												
15	Solar		15,420					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	15,420	27.8%	N/A	27.8%	N/A						
17	<u>Cattle Ranch ST Solar</u>												
18	Solar		16,889					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	16,889	30.5%	N/A	30.5%	N/A						
20	<u>CCEC 3</u>												
21	Gas		464,832				6,728	3,127,193	1,000,000	3,127,193	14,661,955	3.15	4.69
22	Plant Unit Info	1,308.0	464,832	47.8%	93.4%	51.1%	6,728			3,127,193	14,661,955	3.15	
23	<u>Citrus PV Solar</u>												
24	Solar		14,809					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	14,809	26.7%	N/A	26.7%	N/A						
26	<u>Coral Farms PV Solar</u>												
27	Solar		16,719					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	16,719	30.2%	N/A	30.2%	N/A						
29	<u>Desoto Solar</u>												
30	Solar		4,546					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	25.0	4,546	24.4%	N/A	24.4%	N/A						
32	<u>Discovery PV Solar</u>												
33	Solar		12,900					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	12,900	23.3%	N/A	23.3%	N/A						
35	<u>Echo River PV Solar</u>												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		19,942					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	19,942	36.0%	N/A	36.0%	N/A						
3	<u>Egret PV Solar</u>												
4	Solar		14,999					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	14,999	27.1%	N/A	27.1%	N/A						
6	<u>Fort Drum PV Solar</u>												
7	Solar		12,852					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	12,852	23.2%	N/A	23.2%	N/A						
9	<u>Fort Myers 2</u>												
10	Gas		780,024				7,002	5,461,456	1,000,000	5,461,456	25,602,284	3.28	4.69
11	Plant Unit Info	1,700.0	780,024	61.7%	93.8%	65.8%	7,002			5,461,456	25,602,284	3.28	
12	<u>Fort Myers 3A</u>												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	162.0	0	N/A	93.8%	N/A	N/A						
16	<u>Fort Myers 3B</u>												
17	Light Oil		0				0	0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	166.0	0	N/A	93.8%	N/A	N/A						
20	<u>Fort Myers 3C</u>												
21	Light Oil		0				0	0	0	0	0	0.00	0.00
22	Gas		12,041				10,590	127,516	1,000,000	127,516	600,161	4.98	4.71
23	Plant Unit Info	219.0	12,041	7.4%	93.8%	7.9%	10,590			127,516	600,161	4.98	
24	<u>Fort Myers 3D</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		9,900				10,603	104,966	1,000,000	104,966	495,099	5.00	4.72
27	Plant Unit Info	219.0	9,900	6.1%	93.8%	6.5%	10,603			104,966	495,099	5.00	
28	<u>Fort Myers GT</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
31	<u>Hammock PV Solar</u>												
32	Solar		15,832					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	15,832	28.6%	N/A	28.6%	N/A						
34	<u>Hibiscus PV Solar</u>												
35	Solar		15,689					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	15,689	28.3%	N/A	28.3%	N/A						
2	<u>Horizon PV Solar</u>												
3	Solar		16,746					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	16,746	30.2%	N/A	30.2%	N/A						
5	<u>Indian River PV Solar</u>												
6	Solar		16,135					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	16,135	29.1%	N/A	29.1%	N/A						
8	<u>Indiantown FPL</u>												
9	Coal											N/A	0.00
10	Gas		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
12	<u>Interstate PV Solar</u>												
13	Solar		15,280					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	74.5	15,280	27.6%	N/A	27.6%	N/A						
15	<u>Lakeside PV Solar</u>												
16	Solar		14,148					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,148	25.5%	N/A	25.5%	N/A						
18	<u>Lauderdale 1-12</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		0					0	0	0	0	0.00	0.00
21	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
22	<u>Lauderdale 6A</u>												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		6,400				10,559	67,580	1,000,000	67,580	319,712	5.00	4.73
25	Plant Unit Info	216.0	6,400	4.0%	94.0%	4.3%	10,559			67,580	319,712	5.00	
26	<u>Lauderdale 6B</u>												
27	Light Oil		0				0	0	0	0	0	0.00	0.00
28	Gas		6,018				10,565	63,579	1,000,000	63,579	300,209	4.99	4.72
29	Plant Unit Info	216.0	6,018	3.7%	94.0%	4.0%	10,565			63,579	300,209	4.99	
30	<u>Lauderdale 6C</u>												
31	Light Oil		989				15,982	2,711	5,829,998	15,806	207,055	20.94	76.37
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	216.0	989	0.6%	94.0%	0.7%	15,982			15,806	207,055	20.94	
34	<u>Lauderdale 6D</u>												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
3	<u>Lauderdale 6E</u>												
4	Light Oil		494				15,992	1,355	5,830,000	7,900	103,488	20.95	76.37
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	216.0	494	0.3%	94.0%	0.3%	15,992			7,900	103,488	20.95	
7	<u>Loggerhead PV Solar</u>												
8	Solar		16,009					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	16,009	28.9%	N/A	28.9%	N/A						
10	<u>Magnolia PV Solar</u>												
11	Solar		15,519					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	15,519	28.0%	N/A	28.0%	N/A						
13	<u>Manatee 1</u>												
14	Heavy Oil		2,834				11,324	5,015	6,399,997	32,094	379,067	13.37	75.59
15	Gas		65,255				11,324	738,914	1,000,000	738,914	3,329,041	5.10	4.51
16	Plant Unit Info	789.0	68,089	11.6%	94.1%	12.3%	11,324			771,008	3,708,108	5.45	
17	<u>Manatee 2</u>												
18	Heavy Oil		3,532				12,543	6,921	6,400,000	44,296	523,186	14.81	75.59
19	Gas		80,202				12,543	1,005,944	1,000,000	1,005,944	4,534,374	5.65	4.51
20	Plant Unit Info	789.0	83,734	14.3%	94.1%	15.2%	12,543			1,050,240	5,057,560	6.04	
21	<u>Manatee 3</u>												
22	Gas		646,301				6,842	4,421,904	1,000,000	4,421,904	19,919,677	3.08	4.50
23	Plant Unit Info	1,223.0	646,301	71.0%	93.9%	75.7%	6,842			4,421,904	19,919,677	3.08	
24	<u>Manatee PV Solar</u>												
25	Solar		14,533					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,533	26.2%	N/A	26.2%	N/A						
27	<u>Martin 3</u>												
28	Gas		174,716				7,344	1,283,027	1,000,000	1,283,027	5,888,138	3.37	4.59
29	Plant Unit Info	464.0	174,716	50.6%	93.9%	53.9%	7,344			1,283,027	5,888,138	3.37	
30	<u>Martin 4</u>												
31	Gas		172,773				7,307	1,262,463	1,000,000	1,262,463	5,799,986	3.36	4.59
32	Plant Unit Info	464.0	172,773	50.1%	93.9%	53.3%	7,307			1,262,463	5,799,986	3.36	
33	<u>Martin 8</u>												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		631,570				6,919	4,369,660	1,000,000	4,369,660	20,183,140	3.20	4.62

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	1,218.0	631,570	69.7%	93.5%	74.5%	6,919			4,369,660	20,183,140	3.20	
2	<u>Martin 8 Solar</u>												
3	Solar		12,679					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	55.0	12,679	31.0%	N/A	31.0%	N/A						
5	<u>Miami-Dade PV Solar</u>												
6	Solar		14,897					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,897	26.9%	N/A	26.9%	N/A						
8	<u>Nassau PV Solar</u>												
9	Solar		14,620					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,620	26.4%	N/A	26.4%	N/A						
11	<u>Northern Preserve ST Solar</u>												
12	Solar		13,402					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,402	24.2%	N/A	24.2%	N/A						
14	<u>OKEECHOBEE 1</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		1,030,616				6,286	6,478,931	1,000,000	6,478,931	30,585,812	2.97	4.72
17	Plant Unit Info	1,603.0	1,030,616	86.4%	93.0%	92.9%	6,286			6,478,931	30,585,812	2.97	
18	<u>Okeechobee PV Solar</u>												
19	Solar		16,177					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	16,177	29.2%	N/A	29.2%	N/A						
21	<u>Orange Blossom PV Solar</u>												
22	Solar		14,337					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,337	25.9%	N/A	25.9%	N/A						
24	<u>Palm Bay PV Solar</u>												
25	Solar		14,236					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,236	25.7%	N/A	25.7%	N/A						
27	<u>PEEC</u>												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		811,028				6,366	5,162,662	1,000,000	5,162,662	24,196,503	2.98	4.69
30	Plant Unit Info	1,254.0	811,028	86.9%	93.0%	93.5%	6,366			5,162,662	24,196,503	2.98	
31	<u>Pelican PV Solar</u>												
32	Solar		14,337					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	14,337	25.9%	N/A	25.9%	N/A						
34	<u>Pioneer Trail PV Solar</u>												
35	Solar		15,188					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	15,188	27.4%	N/A	27.4%	N/A						
2	<u>Riviera 5</u>												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		626,614				6,655	4,170,036	1,000,000	4,170,036	19,685,654	3.14	4.72
5	Plant Unit Info	1,308.0	626,614	64.4%	93.4%	68.9%	6,655			4,170,036	19,685,654	3.14	
6	<u>Rodeo PV Solar</u>												
7	Solar		14,826					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	14,826	26.8%	N/A	26.8%	N/A						
9	<u>Sabal Palm PV Solar</u>												
10	Solar		14,072					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	14,072	25.4%	N/A	25.4%	N/A						
12	<u>Sanford 4</u>												
13	Gas		465,941				6,983	3,253,829	1,000,000	3,253,829	15,260,521	3.28	4.69
14	Plant Unit Info	1,147.0	465,941	54.6%	94.1%	58.0%	6,983			3,253,829	15,260,521	3.28	
15	<u>Sanford 5</u>												
16	Gas		461,912				6,970	3,219,577	1,000,000	3,219,577	15,098,889	3.27	4.69
17	Plant Unit Info	1,147.0	461,912	54.1%	94.1%	57.5%	6,970			3,219,577	15,098,889	3.27	
18	<u>Scherer 4</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Coal		248,246				11,021	160,934	17,000,000	2,735,886	7,380,430	2.97	45.86
21	Plant Unit Info	636.0	248,246	52.5%	92.2%	56.9%	11,021			2,735,886	7,380,430	2.97	
22	<u>Southfork PV Solar</u>												
23	Solar		18,794					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	18,794	33.9%	N/A	33.9%	N/A						
25	<u>Space Coast</u>												
26	Solar		1,555					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10.0	1,555	20.9%	100.0%	20.9%	N/A						
28	<u>St Lucie 1</u>												
29	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,602,343	0.51	0.48
30	Plant Unit Info	981.0	711,586	97.5%	97.5%	100.0%	10,560			7,514,275	3,602,343	0.51	
31	<u>St Lucie 2</u>												
32	Nuclear		609,292				10,496	6,394,944	1,000,000	6,394,944	2,785,637	0.46	0.44
33	Plant Unit Info	840.0	609,292	97.5%	97.5%	100.0%	10,496			6,394,944	2,785,637	0.46	
34	<u>Sunshine Gateway PV Solar</u>												
35	Solar		16,190					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	16,190	29.2%	N/A	29.2%	N/A						
2	<u>Sweetbay PV Solar</u>												
3	Solar		13,905					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,905	25.1%	N/A	25.1%	N/A						
5	<u>Trailside PV Solar</u>												
6	Solar		15,674					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,674	28.3%	N/A	28.3%	N/A						
8	<u>Turkey Point 3</u>												
9	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,131,956	0.52	0.48
10	Plant Unit Info	837.0	607,178	97.5%	97.5%	100.0%	10,818			6,568,699	3,131,956	0.52	
11	<u>Turkey Point 4</u>												
12	Nuclear		612,238				10,729	6,568,514	1,000,000	6,568,514	3,889,874	0.64	0.59
13	Plant Unit Info	844.0	612,238	97.5%	97.5%	100.0%	10,729			6,568,514	3,889,874	0.64	
14	<u>Turkey Point 5</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		559,840				6,883	3,853,282	1,000,000	3,853,282	18,070,154	3.23	4.69
17	Plant Unit Info	1,256.0	559,840	59.9%	93.9%	63.8%	6,883			3,853,282	18,070,154	3.23	
18	<u>Twin Lakes ST Solar</u>												
19	Solar		16,435					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	16,435	29.7%	N/A	29.7%	N/A						
21	<u>Union Springs PV Solar</u>												
22	Solar		15,697					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,697	28.3%	N/A	28.3%	N/A						
24	<u>WCEC 01</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		547,796				6,772	3,709,832	1,000,000	3,709,832	16,710,546	3.05	4.50
27	Plant Unit Info	1,223.0	547,796	60.2%	93.7%	64.2%	6,772			3,709,832	16,710,546	3.05	
28	<u>WCEC 02</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Gas		577,468				6,758	3,902,570	1,000,000	3,902,570	17,578,715	3.04	4.50
31	Plant Unit Info	1,223.0	577,468	63.5%	93.7%	67.7%	6,758			3,902,570	17,578,715	3.04	
32	<u>WCEC 03</u>												
33	Light Oil		0				0	0	0	0	0	0.00	0.00
34	Gas		640,384				6,713	4,298,985	1,000,000	4,298,985	19,364,334	3.02	4.50
35	Plant Unit Info	1,228.0	640,384	70.1%	93.7%	74.8%	6,713			4,298,985	19,364,334	3.02	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Wildflower PV Solar</u>												
2	Solar		15,980					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	15,980	28.8%	N/A	28.8%	N/A						
4	<u>Willow PV Solar</u>												
5	Solar		15,198					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	15,198	27.4%	N/A	27.4%	N/A						
7	<u>System Totals</u>												
8	Plant Unit Info	28,323	12,187,016				7,382			89,966,320	300,187,942	2.46	N/A
9	Total												
10													
11													
12													
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SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Aug - 2021</u>												
2	<u>Babcock Preserve ST Solar</u>												
3	Solar		14,937					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,937	27.0%	N/A	27.0%	N/A						
5	<u>Babcock PV Solar</u>												
6	Solar		14,342					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,342	25.9%	N/A	25.9%	N/A						
8	<u>Barefoot PV Solar</u>												
9	Solar		15,018					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,018	27.1%	N/A	27.1%	N/A						
11	<u>Blue Cypress PV Solar</u>												
12	Solar		15,243					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	15,243	27.5%	N/A	27.5%	N/A						
14	<u>Blue Heron ST Solar</u>												
15	Solar		14,937					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,937	27.0%	N/A	27.0%	N/A						
17	<u>Cattle Ranch ST Solar</u>												
18	Solar		15,651					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	15,651	28.2%	N/A	28.2%	N/A						
20	<u>CCEC 3</u>												
21	Gas		477,973				6,721	3,212,608	1,000,000	3,212,608	15,064,002	3.15	4.69
22	Plant Unit Info	1,308.0	477,973	49.1%	93.4%	52.6%	6,721			3,212,608	15,064,002	3.15	
23	<u>Citrus PV Solar</u>												
24	Solar		14,611					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	14,611	26.4%	N/A	26.4%	N/A						
26	<u>Coral Farms PV Solar</u>												
27	Solar		16,129					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	16,129	29.1%	N/A	29.1%	N/A						
29	<u>Desoto Solar</u>												
30	Solar		4,326					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	25.0	4,326	23.3%	N/A	23.3%	N/A						
32	<u>Discovery PV Solar</u>												
33	Solar		12,412					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	12,412	22.4%	N/A	22.4%	N/A						
35	<u>Echo River PV Solar</u>												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		18,710					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	18,710	33.8%	N/A	33.8%	N/A						
3	<u>Egret PV Solar</u>												
4	Solar		13,338					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	13,338	24.1%	N/A	24.1%	N/A						
6	<u>Fort Drum PV Solar</u>												
7	Solar		12,697					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	12,697	22.9%	N/A	22.9%	N/A						
9	<u>Fort Myers 2</u>												
10	Gas		813,295				7,005	5,696,935	1,000,000	5,696,935	26,708,855	3.28	4.69
11	Plant Unit Info	1,700.0	813,295	64.3%	93.8%	68.6%	7,005			5,696,935	26,708,855	3.28	
12	<u>Fort Myers 3A</u>												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	162.0	0	N/A	93.8%	N/A	N/A						
16	<u>Fort Myers 3B</u>												
17	Light Oil		0				0	0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	166.0	0	N/A	93.8%	N/A	N/A						
20	<u>Fort Myers 3C</u>												
21	Light Oil		0				0	0	0	0	0	0.00	0.00
22	Gas		16,649				10,526	175,255	1,000,000	175,255	823,232	4.94	4.70
23	Plant Unit Info	219.0	16,649	10.2%	93.8%	10.9%	10,526			175,255	823,232	4.94	
24	<u>Fort Myers 3D</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		16,493				10,517	173,462	1,000,000	173,462	815,290	4.94	4.70
27	Plant Unit Info	219.0	16,493	10.1%	93.8%	10.8%	10,517			173,462	815,290	4.94	
28	<u>Fort Myers GT</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
31	<u>Hammock PV Solar</u>												
32	Solar		15,279					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	15,279	27.6%	N/A	27.6%	N/A						
34	<u>Hibiscus PV Solar</u>												
35	Solar		15,424					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	15,424	27.8%	N/A	27.8%	N/A						
2	<u>Horizon PV Solar</u>												
3	Solar		16,140					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	16,140	29.1%	N/A	29.1%	N/A						
5	<u>Indian River PV Solar</u>												
6	Solar		15,230					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,230	27.5%	N/A	27.5%	N/A						
8	<u>Indiantown FPL</u>												
9	Coal											N/A	0.00
10	Gas		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
12	<u>Interstate PV Solar</u>												
13	Solar		15,104					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	74.5	15,104	27.3%	N/A	27.3%	N/A						
15	<u>Lakeside PV Solar</u>												
16	Solar		13,728					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	13,728	24.8%	N/A	24.8%	N/A						
18	<u>Lauderdale 1-12</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		0					0	0	0	0	0.00	0.00
21	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
22	<u>Lauderdale 6A</u>												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		13,129				10,576	138,848	1,000,000	138,848	653,471	4.98	4.71
25	Plant Unit Info	216.0	13,129	8.2%	94.0%	8.7%	10,576			138,848	653,471	4.98	
26	<u>Lauderdale 6B</u>												
27	Light Oil		0				0	0	0	0	0	0.00	0.00
28	Gas		12,527				10,615	132,970	1,000,000	132,970	625,399	4.99	4.70
29	Plant Unit Info	216.0	12,527	7.8%	94.0%	8.3%	10,615			132,970	625,399	4.99	
30	<u>Lauderdale 6C</u>												
31	Light Oil		644				13,738	1,518	5,829,984	8,847	115,894	18.00	76.37
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	216.0	644	0.4%	94.0%	0.4%	13,738			8,847	115,894	18.00	
34	<u>Lauderdale 6D</u>												
35	Light Oil		942				16,466	2,661	5,829,998	15,511	203,191	21.57	76.37

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	216.0	942	0.6%	94.0%	0.6%	16,466			15,511	203,191	21.57	
3	<u>Lauderdale 6E</u>												
4	Light Oil		671				13,440	1,547	5,829,988	9,018	118,134	17.61	76.37
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	216.0	671	0.4%	94.0%	0.5%	13,440			9,018	118,134	17.61	
7	<u>Loggerhead PV Solar</u>												
8	Solar		15,258					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	15,258	27.5%	N/A	27.5%	N/A						
10	<u>Magnolia PV Solar</u>												
11	Solar		14,179					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	14,179	25.6%	N/A	25.6%	N/A						
13	<u>Manatee 1</u>												
14	Heavy Oil		8,159				10,586	13,496	6,400,001	86,373	1,020,164	12.50	75.59
15	Gas		159,392				10,586	1,687,266	1,000,000	1,687,266	7,567,898	4.75	4.49
16	Plant Unit Info	789.0	167,551	28.5%	94.1%	30.3%	10,586			1,773,639	8,588,062	5.13	
17	<u>Manatee 2</u>												
18	Heavy Oil		6,033				12,419	11,707	6,399,997	74,924	884,938	14.67	75.59
19	Gas		79,168				12,419	983,228	1,000,000	983,228	4,409,266	5.57	4.48
20	Plant Unit Info	789.0	85,201	14.5%	94.1%	15.4%	12,419			1,058,152	5,294,204	6.21	
21	<u>Manatee 3</u>												
22	Gas		656,320				6,825	4,479,425	1,000,000	4,479,425	20,078,210	3.06	4.48
23	Plant Unit Info	1,223.0	656,320	72.1%	93.9%	76.8%	6,825			4,479,425	20,078,210	3.06	
24	<u>Manatee PV Solar</u>												
25	Solar		14,390					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,390	26.0%	N/A	26.0%	N/A						
27	<u>Martin 3</u>												
28	Gas		186,018				7,319	1,361,552	1,000,000	1,361,552	6,285,831	3.38	4.62
29	Plant Unit Info	464.0	186,018	53.9%	93.9%	57.4%	7,319			1,361,552	6,285,831	3.38	
30	<u>Martin 4</u>												
31	Gas		182,346				7,324	1,335,589	1,000,000	1,335,589	6,165,968	3.38	4.62
32	Plant Unit Info	464.0	182,346	52.8%	93.9%	56.2%	7,324			1,335,589	6,165,968	3.38	
33	<u>Martin 8</u>												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		620,956				6,916	4,294,518	1,000,000	4,294,518	19,951,359	3.21	4.65

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	1,218.0	620,956	68.5%	93.5%	73.3%	6,916			4,294,518	19,951,359	3.21	
2	<u>Martin 8 Solar</u>												
3	Solar		11,873					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	55.0	11,873	29.0%	N/A	29.0%	N/A						
5	<u>Miami-Dade PV Solar</u>												
6	Solar		14,745					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,745	26.6%	N/A	26.6%	N/A						
8	<u>Nassau PV Solar</u>												
9	Solar		12,931					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,931	23.3%	N/A	23.3%	N/A						
11	<u>Northern Preserve ST Solar</u>												
12	Solar		12,982					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,982	23.4%	N/A	23.4%	N/A						
14	<u>OKEECHOBEE 1</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		1,066,654				6,276	6,694,378	1,000,000	6,694,378	31,657,587	2.97	4.73
17	Plant Unit Info	1,603.0	1,066,654	89.4%	93.0%	96.2%	6,276			6,694,378	31,657,587	2.97	
18	<u>Okeechobee PV Solar</u>												
19	Solar		15,842					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	15,842	28.6%	N/A	28.6%	N/A						
21	<u>Orange Blossom PV Solar</u>												
22	Solar		13,405					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	13,405	24.2%	N/A	24.2%	N/A						
24	<u>Palm Bay PV Solar</u>												
25	Solar		13,282					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,282	24.0%	N/A	24.0%	N/A						
27	<u>PEEC</u>												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		789,155				6,368	5,024,975	1,000,000	5,024,975	23,569,483	2.99	4.69
30	Plant Unit Info	1,254.0	789,155	84.6%	93.0%	91.0%	6,368			5,024,975	23,569,483	2.99	
31	<u>Pelican PV Solar</u>												
32	Solar		13,405					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	13,405	24.2%	N/A	24.2%	N/A						
34	<u>Pioneer Trail PV Solar</u>												
35	Solar		15,069					N/A	N/A	N/A	N/A	N/A	N/A

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SCHEDULE E4

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	15,069	27.2%	N/A	27.2%	N/A						
2	<u>Riviera 5</u>												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		627,930				6,655	4,178,928	1,000,000	4,178,928	19,761,978	3.15	4.73
5	Plant Unit Info	1,308.0	627,930	64.5%	93.4%	69.1%	6,655			4,178,928	19,761,978	3.15	
6	<u>Rodeo PV Solar</u>												
7	Solar		14,363					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	14,363	25.9%	N/A	25.9%	N/A						
9	<u>Sabal Palm PV Solar</u>												
10	Solar		13,623					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	13,623	24.6%	N/A	24.6%	N/A						
12	<u>Sanford 4</u>												
13	Gas		488,494				6,948	3,394,232	1,000,000	3,394,232	15,928,926	3.26	4.69
14	Plant Unit Info	1,147.0	488,494	57.2%	94.1%	60.8%	6,948			3,394,232	15,928,926	3.26	
15	<u>Sanford 5</u>												
16	Gas		491,705				6,950	3,417,109	1,000,000	3,417,109	16,037,769	3.26	4.69
17	Plant Unit Info	1,147.0	491,705	57.6%	94.1%	61.2%	6,950			3,417,109	16,037,769	3.26	
18	<u>Scherer 4</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Coal		259,455				10,972	167,453	17,000,000	2,846,705	7,533,974	2.90	44.99
21	Plant Unit Info	636.0	259,455	54.8%	92.2%	59.5%	10,972			2,846,705	7,533,974	2.90	
22	<u>Southfork PV Solar</u>												
23	Solar		18,357					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	18,357	33.1%	N/A	33.1%	N/A						
25	<u>Space Coast</u>												
26	Solar		1,545					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10.0	1,545	20.8%	100.0%	20.8%	N/A						
28	<u>St Lucie 1</u>												
29	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,602,343	0.51	0.48
30	Plant Unit Info	981.0	711,586	97.5%	97.5%	100.0%	10,560			7,514,275	3,602,343	0.51	
31	<u>St Lucie 2</u>												
32	Nuclear		530,674				10,496	5,569,790	1,000,000	5,569,790	2,426,200	0.46	0.44
33	Plant Unit Info	840.0	530,674	84.6%	84.6%	100.0%	10,496			5,569,790	2,426,200	0.46	
34	<u>Sunshine Gateway PV Solar</u>												
35	Solar		15,292					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	15,292	27.6%	N/A	27.6%	N/A						
2	<u>Sweetbay PV Solar</u>												
3	Solar		13,274					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,274	24.0%	N/A	24.0%	N/A						
5	<u>Trailside PV Solar</u>												
6	Solar		14,652					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,652	26.4%	N/A	26.4%	N/A						
8	<u>Turkey Point 3</u>												
9	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,131,956	0.52	0.48
10	Plant Unit Info	837.0	607,178	97.5%	97.5%	100.0%	10,818			6,568,699	3,131,956	0.52	
11	<u>Turkey Point 4</u>												
12	Nuclear		612,238				10,729	6,568,514	1,000,000	6,568,514	3,889,874	0.64	0.59
13	Plant Unit Info	844.0	612,238	97.5%	97.5%	100.0%	10,729			6,568,514	3,889,874	0.64	
14	<u>Turkey Point 5</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		577,646				6,870	3,968,350	1,000,000	3,968,350	18,623,959	3.22	4.69
17	Plant Unit Info	1,256.0	577,646	61.8%	93.9%	65.8%	6,870			3,968,350	18,623,959	3.22	
18	<u>Twin Lakes ST Solar</u>												
19	Solar		15,230					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	15,230	27.5%	N/A	27.5%	N/A						
21	<u>Union Springs PV Solar</u>												
22	Solar		14,342					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,342	25.9%	N/A	25.9%	N/A						
24	<u>WCEC 01</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		476,843				6,810	3,247,092	1,000,000	3,247,092	14,550,710	3.05	4.48
27	Plant Unit Info	1,223.0	476,843	52.4%	93.7%	55.9%	6,810			3,247,092	14,550,710	3.05	
28	<u>WCEC 02</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Gas		574,136				6,755	3,878,300	1,000,000	3,878,300	17,380,575	3.03	4.48
31	Plant Unit Info	1,223.0	574,136	63.1%	93.7%	67.3%	6,755			3,878,300	17,380,575	3.03	
32	<u>WCEC 03</u>												
33	Light Oil		0				0	0	0	0	0	0.00	0.00
34	Gas		700,701				6,666	4,670,528	1,000,000	4,670,528	20,931,635	2.99	4.48
35	Plant Unit Info	1,228.0	700,701	76.7%	93.7%	81.8%	6,666			4,670,528	20,931,635	2.99	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Wildflower PV Solar</u>												
2	Solar		15,359					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	15,359	27.7%	N/A	27.7%	N/A						
4	<u>Willow PV Solar</u>												
5	Solar		14,101					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	14,101	25.4%	N/A	25.4%	N/A						
7	<u>System Totals</u>												
8	Plant Unit Info	28,323	12,355,865				7,398			91,408,204	310,518,070	2.51	N/A
9	Total												
10													
11													
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SCHEDULE E4

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Sep - 2021</u>												
2	<u>Babcock Preserve ST Solar</u>												
3	Solar		14,167					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,167	26.4%	N/A	26.4%	N/A						
5	<u>Babcock PV Solar</u>												
6	Solar		12,899					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,899	24.1%	N/A	24.1%	N/A						
8	<u>Barefoot PV Solar</u>												
9	Solar		13,957					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,957	26.0%	N/A	26.0%	N/A						
11	<u>Blue Cypress PV Solar</u>												
12	Solar		14,290					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,290	26.6%	N/A	26.6%	N/A						
14	<u>Blue Heron ST Solar</u>												
15	Solar		14,167					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,167	26.4%	N/A	26.4%	N/A						
17	<u>Cattle Ranch ST Solar</u>												
18	Solar		14,415					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,415	26.9%	N/A	26.9%	N/A						
20	<u>CCEC 3</u>												
21	Gas		411,829				6,742	2,776,352	1,000,000	2,776,352	12,970,625	3.15	4.67
22	Plant Unit Info	1,308.0	411,829	43.7%	75.7%	57.8%	6,742			2,776,352	12,970,625	3.15	
23	<u>Citrus PV Solar</u>												
24	Solar		13,630					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	13,630	25.4%	N/A	25.4%	N/A						
26	<u>Coral Farms PV Solar</u>												
27	Solar		14,602					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	14,602	27.2%	N/A	27.2%	N/A						
29	<u>Desoto Solar</u>												
30	Solar		3,868					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	25.0	3,868	21.5%	N/A	21.5%	N/A						
32	<u>Discovery PV Solar</u>												
33	Solar		11,389					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	11,389	21.2%	N/A	21.2%	N/A						
35	<u>Echo River PV Solar</u>												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		16,335					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	16,335	30.5%	N/A	30.5%	N/A						
3	<u>Egret PV Solar</u>												
4	Solar		11,797					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	11,797	22.0%	N/A	22.0%	N/A						
6	<u>Fort Drum PV Solar</u>												
7	Solar		11,487					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	11,487	21.4%	N/A	21.4%	N/A						
9	<u>Fort Myers 2</u>												
10	Gas		798,910				7,003	5,594,691	1,000,000	5,594,691	26,143,530	3.27	4.67
11	Plant Unit Info	1,700.0	798,910	65.3%	93.8%	69.6%	7,003			5,594,691	26,143,530	3.27	
12	<u>Fort Myers 3A</u>												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	162.0	0	N/A	93.8%	N/A	N/A						
16	<u>Fort Myers 3B</u>												
17	Light Oil		908				14,086	2,194	5,829,987	12,790	207,707	22.88	94.68
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	166.0	908	0.8%	93.8%	0.8%	14,086			12,790	207,707	22.88	
20	<u>Fort Myers 3C</u>												
21	Light Oil		0				0	0	0	0	0	0.00	0.00
22	Gas		18,544				10,542	195,496	1,000,000	195,496	915,590	4.94	4.68
23	Plant Unit Info	219.0	18,544	11.8%	93.8%	12.5%	10,542			195,496	915,590	4.94	
24	<u>Fort Myers 3D</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		20,250				10,471	212,044	1,000,000	212,044	991,721	4.90	4.68
27	Plant Unit Info	219.0	20,250	12.8%	93.8%	13.7%	10,471			212,044	991,721	4.90	
28	<u>Fort Myers GT</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
31	<u>Hammock PV Solar</u>												
32	Solar		14,411					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	14,411	26.9%	N/A	26.9%	N/A						
34	<u>Hibiscus PV Solar</u>												
35	Solar		13,975					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	13,975	26.1%	N/A	26.1%	N/A						
2	<u>Horizon PV Solar</u>												
3	Solar		14,806					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,806	27.6%	N/A	27.6%	N/A						
5	<u>Indian River PV Solar</u>												
6	Solar		14,277					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,277	26.6%	N/A	26.6%	N/A						
8	<u>Indiantown FPL</u>												
9	Coal											N/A	0.00
10	Gas		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
12	<u>Interstate PV Solar</u>												
13	Solar		14,079					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	74.5	14,079	26.3%	N/A	26.3%	N/A						
15	<u>Lakeside PV Solar</u>												
16	Solar		12,736					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	12,736	23.7%	N/A	23.7%	N/A						
18	<u>Lauderdale 1-12</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		0					0	0	0	0	0.00	0.00
21	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
22	<u>Lauderdale 6A</u>												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		15,446				10,518	162,465	1,000,000	162,465	760,884	4.93	4.68
25	Plant Unit Info	216.0	15,446	9.9%	94.0%	10.6%	10,518			162,465	760,884	4.93	
26	<u>Lauderdale 6B</u>												
27	Light Oil		0				0	0	0	0	0	0.00	0.00
28	Gas		15,045				10,525	158,347	1,000,000	158,347	741,882	4.93	4.69
29	Plant Unit Info	216.0	15,045	9.7%	94.0%	10.3%	10,525			158,347	741,882	4.93	
30	<u>Lauderdale 6C</u>												
31	Light Oil		2,733				14,731	6,906	5,830,002	40,261	548,224	20.06	79.39
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	216.0	2,733	1.8%	94.0%	1.9%	14,731			40,261	548,224	20.06	
34	<u>Lauderdale 6D</u>												
35	Light Oil		2,318				13,789	5,483	5,830,005	31,963	435,232	18.78	79.39

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	216.0	2,318	1.5%	94.0%	1.6%	13,789			31,963	435,232	18.78	
3	<u>Lauderdale 6E</u>												
4	Light Oil		1,379				14,765	3,492	5,830,005	20,361	277,251	20.11	79.39
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	216.0	1,379	0.9%	94.0%	1.0%	14,765			20,361	277,251	20.11	
7	<u>Loggerhead PV Solar</u>												
8	Solar		14,449					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	14,449	26.9%	N/A	26.9%	N/A						
10	<u>Magnolia PV Solar</u>												
11	Solar		12,435					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	12,435	23.2%	N/A	23.2%	N/A						
13	<u>Manatee 1</u>												
14	Heavy Oil		10,663				10,845	18,069	6,400,000	115,643	1,365,876	12.81	75.59
15	Gas		64,284				10,845	697,187	1,000,000	697,187	3,104,095	4.83	4.45
16	Plant Unit Info	789.0	74,947	13.2%	94.1%	14.0%	10,845			812,830	4,469,971	5.96	
17	<u>Manatee 2</u>												
18	Heavy Oil		9,280				12,145	17,610	6,400,001	112,706	1,331,187	14.34	75.59
19	Gas		79,444				12,145	964,862	1,000,000	964,862	4,292,254	5.40	4.45
20	Plant Unit Info	789.0	88,724	15.6%	94.1%	16.6%	12,145			1,077,568	5,623,440	6.34	
21	<u>Manatee 3</u>												
22	Gas		662,202				6,811	4,510,556	1,000,000	4,510,556	20,065,922	3.03	4.45
23	Plant Unit Info	1,223.0	662,202	75.2%	93.9%	80.1%	6,811			4,510,556	20,065,922	3.03	
24	<u>Manatee PV Solar</u>												
25	Solar		13,678					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,678	25.5%	N/A	25.5%	N/A						
27	<u>Martin 3</u>												
28	Gas		183,786				7,323	1,345,802	1,000,000	1,345,802	6,130,297	3.34	4.56
29	Plant Unit Info	464.0	183,786	55.0%	93.9%	58.6%	7,323			1,345,802	6,130,297	3.34	
30	<u>Martin 4</u>												
31	Gas		82,110				7,321	601,123	1,000,000	601,123	2,749,572	3.35	4.57
32	Plant Unit Info	464.0	82,110	24.6%	40.6%	60.6%	7,321			601,123	2,749,572	3.35	
33	<u>Martin 8</u>												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		626,615				6,898	4,322,478	1,000,000	4,322,478	19,895,585	3.18	4.60

FLORIDA POWER & LIGHT COMPANY
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SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	1,218.0	626,615	71.5%	93.5%	76.4%	6,898			4,322,478	19,895,585	3.18	
2	<u>Martin 8 Solar</u>												
3	Solar		10,320					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	55.0	10,320	26.1%	N/A	26.1%	N/A						
5	<u>Miami-Dade PV Solar</u>												
6	Solar		13,518					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,518	25.2%	N/A	25.2%	N/A						
8	<u>Nassau PV Solar</u>												
9	Solar		11,335					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	11,335	21.1%	N/A	21.1%	N/A						
11	<u>Northern Preserve ST Solar</u>												
12	Solar		12,314					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,314	23.0%	N/A	23.0%	N/A						
14	<u>OKEECHOBEE 1</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		1,040,622				6,273	6,528,239	1,000,000	6,528,239	30,584,980	2.94	4.69
17	Plant Unit Info	1,603.0	1,040,622	90.2%	93.0%	97.0%	6,273			6,528,239	30,584,980	2.94	
18	<u>Okeechobee PV Solar</u>												
19	Solar		14,608					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	14,608	27.2%	N/A	27.2%	N/A						
21	<u>Orange Blossom PV Solar</u>												
22	Solar		12,397					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,397	23.1%	N/A	23.1%	N/A						
24	<u>Palm Bay PV Solar</u>												
25	Solar		12,260					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,260	22.9%	N/A	22.9%	N/A						
27	<u>PEEC</u>												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		793,949				6,361	5,050,235	1,000,000	5,050,235	23,603,414	2.97	4.67
30	Plant Unit Info	1,254.0	793,949	87.9%	93.0%	94.6%	6,361			5,050,235	23,603,414	2.97	
31	<u>Pelican PV Solar</u>												
32	Solar		12,397					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	12,397	23.1%	N/A	23.1%	N/A						
34	<u>Pioneer Trail PV Solar</u>												
35	Solar		13,694					N/A	N/A	N/A	N/A	N/A	N/A

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SCHEDULE E4

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	13,694	25.5%	N/A	25.5%	N/A						
2	<u>Riviera 5</u>												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		612,085				6,652	4,071,677	1,000,000	4,071,677	19,075,919	3.12	4.69
5	Plant Unit Info	1,308.0	612,085	65.0%	93.4%	69.6%	6,652			4,071,677	19,075,919	3.12	
6	<u>Rodeo PV Solar</u>												
7	Solar		13,109					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	13,109	24.4%	N/A	24.4%	N/A						
9	<u>Sabal Palm PV Solar</u>												
10	Solar		12,575					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	12,575	23.4%	N/A	23.4%	N/A						
12	<u>Sanford 4</u>												
13	Gas		487,013				6,969	3,393,853	1,000,000	3,393,853	15,862,783	3.26	4.67
14	Plant Unit Info	1,147.0	487,013	59.0%	94.1%	62.7%	6,969			3,393,853	15,862,783	3.26	
15	<u>Sanford 5</u>												
16	Gas		484,903				6,972	3,380,876	1,000,000	3,380,876	15,801,925	3.26	4.67
17	Plant Unit Info	1,147.0	484,903	58.7%	94.1%	62.4%	6,972			3,380,876	15,801,925	3.26	
18	<u>Scherer 4</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Coal		250,325				10,973	161,571	17,000,000	2,746,710	7,169,634	2.86	44.37
21	Plant Unit Info	636.0	250,325	54.7%	92.2%	59.3%	10,973			2,746,710	7,169,634	2.86	
22	<u>Southfork PV Solar</u>												
23	Solar		16,374					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	16,374	30.5%	N/A	30.5%	N/A						
25	<u>Space Coast</u>												
26	Solar		1,421					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10.0	1,421	19.7%	100.0%	19.7%	N/A						
28	<u>St Lucie 1</u>												
29	Nuclear		688,631				10,560	7,271,879	1,000,000	7,271,879	3,486,138	0.51	0.48
30	Plant Unit Info	981.0	688,631	97.5%	97.5%	100.0%	10,560			7,271,879	3,486,138	0.51	
31	<u>St Lucie 2</u>												
32	Nuclear											N/A	0.00
33	Plant Unit Info	840.0	0	N/A	N/A	N/A	N/A						
34	<u>Sunshine Gateway PV Solar</u>												
35	Solar		14,199					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	14,199	26.5%	N/A	26.5%	N/A						
2	<u>Sweetbay PV Solar</u>												
3	Solar		12,663					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,663	23.6%	N/A	23.6%	N/A						
5	<u>Trailside PV Solar</u>												
6	Solar		12,560					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,560	23.4%	N/A	23.4%	N/A						
8	<u>Turkey Point 3</u>												
9	Nuclear		587,592				10,818	6,356,806	1,000,000	6,356,806	3,030,925	0.52	0.48
10	Plant Unit Info	837.0	587,592	97.5%	97.5%	100.0%	10,818			6,356,806	3,030,925	0.52	
11	<u>Turkey Point 4</u>												
12	Nuclear		592,488				10,729	6,356,626	1,000,000	6,356,626	3,764,394	0.64	0.59
13	Plant Unit Info	844.0	592,488	97.5%	97.5%	100.0%	10,729			6,356,626	3,764,394	0.64	
14	<u>Turkey Point 5</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		568,252				6,868	3,902,783	1,000,000	3,902,783	18,242,393	3.21	4.67
17	Plant Unit Info	1,256.0	568,252	62.8%	93.9%	66.9%	6,868			3,902,783	18,242,393	3.21	
18	<u>Twin Lakes ST Solar</u>												
19	Solar		14,028					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	14,028	26.2%	N/A	26.2%	N/A						
21	<u>Union Springs PV Solar</u>												
22	Solar		12,577					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,577	23.5%	N/A	23.5%	N/A						
24	<u>WCEC 01</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		552,017				6,761	3,732,124	1,000,000	3,732,124	16,599,485	3.01	4.45
27	Plant Unit Info	1,223.0	552,017	62.7%	91.5%	68.5%	6,761			3,732,124	16,599,485	3.01	
28	<u>WCEC 02</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Gas		553,906				6,756	3,742,237	1,000,000	3,742,237	16,644,238	3.00	4.45
31	Plant Unit Info	1,223.0	553,906	62.9%	93.7%	67.1%	6,756			3,742,237	16,644,238	3.00	
32	<u>WCEC 03</u>												
33	Light Oil		0				0	0	0	0	0	0.00	0.00
34	Gas		705,040				6,645	4,685,109	1,000,000	4,685,109	20,837,777	2.96	4.45
35	Plant Unit Info	1,228.0	705,040	79.7%	93.7%	85.1%	6,645			4,685,109	20,837,777	2.96	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Wildflower PV Solar</u>												
2	Solar		14,791					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	14,791	27.6%	N/A	27.6%	N/A						
4	<u>Willow PV Solar</u>												
5	Solar		13,002					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	13,002	24.2%	N/A	24.2%	N/A						
7	<u>System Totals</u>												
8	Plant Unit Info	28,323	11,464,561				7,248			83,094,281	297,631,438	2.60	N/A
9	Total												
10													
11													
12													
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SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Oct - 2021</u>												
2	<u>Babcock Preserve ST Solar</u>												
3	Solar		14,948					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,948	27.0%	N/A	27.0%	N/A						
5	<u>Babcock PV Solar</u>												
6	Solar		13,941					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,941	25.2%	N/A	25.2%	N/A						
8	<u>Barefoot PV Solar</u>												
9	Solar		14,309					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,309	25.8%	N/A	25.8%	N/A						
11	<u>Blue Cypress PV Solar</u>												
12	Solar		14,540					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,540	26.2%	N/A	26.2%	N/A						
14	<u>Blue Heron ST Solar</u>												
15	Solar		14,948					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,948	27.0%	N/A	27.0%	N/A						
17	<u>Cattle Ranch ST Solar</u>												
18	Solar		14,269					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,269	25.7%	N/A	25.7%	N/A						
20	<u>CCEC 3</u>												
21	Gas		458,482				6,740	3,090,342	1,000,000	3,090,342	15,088,278	3.29	4.88
22	Plant Unit Info	1,308.0	458,482	47.1%	91.3%	51.6%	6,740			3,090,342	15,088,278	3.29	
23	<u>Citrus PV Solar</u>												
24	Solar		14,046					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	14,046	25.3%	N/A	25.3%	N/A						
26	<u>Coral Farms PV Solar</u>												
27	Solar		15,020					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	15,020	27.1%	N/A	27.1%	N/A						
29	<u>Desoto Solar</u>												
30	Solar		3,833					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	25.0	3,833	20.6%	N/A	20.6%	N/A						
32	<u>Discovery PV Solar</u>												
33	Solar		11,518					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	11,518	20.8%	N/A	20.8%	N/A						
35	<u>Echo River PV Solar</u>												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		16,339					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	16,339	29.5%	N/A	29.5%	N/A						
3	<u>Egret PV Solar</u>												
4	Solar		11,683					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	11,683	21.1%	N/A	21.1%	N/A						
6	<u>Fort Drum PV Solar</u>												
7	Solar		11,407					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	11,407	20.6%	N/A	20.6%	N/A						
9	<u>Fort Myers 2</u>												
10	Gas		777,837				7,042	5,477,760	1,000,000	5,477,760	26,728,814	3.44	4.88
11	Plant Unit Info	1,700.0	777,837	61.5%	84.1%	73.1%	7,042			5,477,760	26,728,814	3.44	
12	<u>Fort Myers 3A</u>												
13	Light Oil		1,199				11,604	2,386	5,830,008	13,909	225,880	18.85	94.68
14	Gas		3,125				11,604	36,269	1,000,000	36,269	178,315	5.71	4.92
15	Plant Unit Info	162.0	4,324	3.6%	93.8%	3.8%	11,604			50,178	404,194	9.35	
16	<u>Fort Myers 3B</u>												
17	Light Oil		1,820				11,682	3,646	5,829,999	21,256	345,193	18.97	94.68
18	Gas		2,972				11,682	34,714	1,000,000	34,714	170,977	5.75	4.93
19	Plant Unit Info	166.0	4,791	3.9%	93.8%	4.1%	11,682			55,970	516,170	10.77	
20	<u>Fort Myers 3C</u>												
21	Light Oil		506				10,663	926	5,829,984	5,396	87,630	17.32	94.68
22	Gas		20,132				10,663	214,658	1,000,000	214,658	1,054,605	5.24	4.91
23	Plant Unit Info	219.0	20,638	12.7%	93.8%	13.5%	10,663			220,054	1,142,235	5.53	
24	<u>Fort Myers 3D</u>												
25	Light Oil		283				10,604	515	5,829,997	3,000	48,719	17.22	94.68
26	Gas		21,895				10,604	232,182	1,000,000	232,182	1,140,540	5.21	4.91
27	Plant Unit Info	219.0	22,178	13.6%	93.8%	14.5%	10,604			235,182	1,189,260	5.36	
28	<u>Fort Myers GT</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
31	<u>Hammock PV Solar</u>												
32	Solar		15,340					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	15,340	27.7%	N/A	27.7%	N/A						
34	<u>Hibiscus PV Solar</u>												
35	Solar		13,972					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
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SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	13,972	25.2%	N/A	25.2%	N/A						
2	<u>Horizon PV Solar</u>												
3	Solar		15,171					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	15,171	27.4%	N/A	27.4%	N/A						
5	<u>Indian River PV Solar</u>												
6	Solar		14,532					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,532	26.2%	N/A	26.2%	N/A						
8	<u>Indiantown FPL</u>												
9	Coal											N/A	0.00
10	Gas		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
12	<u>Interstate PV Solar</u>												
13	Solar		14,238					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	74.5	14,238	25.7%	N/A	25.7%	N/A						
15	<u>Lakeside PV Solar</u>												
16	Solar		12,782					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	12,782	23.1%	N/A	23.1%	N/A						
18	<u>Lauderdale 1-12</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		0					0	0	0	0	0.00	0.00
21	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
22	<u>Lauderdale 6A</u>												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		18,656				10,507	196,014	1,000,000	196,014	961,436	5.15	4.90
25	Plant Unit Info	216.0	18,656	11.6%	94.0%	12.4%	10,507			196,014	961,436	5.15	
26	<u>Lauderdale 6B</u>												
27	Light Oil		0				0	0	0	0	0	0.00	0.00
28	Gas		15,638				10,517	164,470	1,000,000	164,470	807,495	5.16	4.91
29	Plant Unit Info	216.0	15,638	9.7%	94.0%	10.4%	10,517			164,470	807,495	5.16	
30	<u>Lauderdale 6C</u>												
31	Light Oil		0				0	0	0	0	0	0.00	0.00
32	Gas		15,937				10,540	167,978	1,000,000	167,978	824,115	5.17	4.91
33	Plant Unit Info	216.0	15,937	9.9%	94.0%	10.6%	10,540			167,978	824,115	5.17	
34	<u>Lauderdale 6D</u>												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		12,728				10,562	134,430	1,000,000	134,430	659,962	5.19	4.91
2	Plant Unit Info	216.0	12,728	7.9%	94.0%	8.5%	10,562			134,430	659,962	5.19	
3	<u>Lauderdale 6E</u>												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		16,850				10,515	177,180	1,000,000	177,180	870,275	5.16	4.91
6	Plant Unit Info	216.0	16,850	10.5%	94.0%	11.2%	10,515			177,180	870,275	5.16	
7	<u>Loggerhead PV Solar</u>												
8	Solar		14,876					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	14,876	26.8%	N/A	26.8%	N/A						
10	<u>Magnolia PV Solar</u>												
11	Solar		12,256					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	12,256	22.1%	N/A	22.1%	N/A						
13	<u>Manatee 1</u>												
14	Heavy Oil		5,367				11,889	9,970	6,399,998	63,806	753,622	14.04	75.59
15	Gas		20,923				11,889	248,749	1,000,000	248,749	1,158,193	5.54	4.66
16	Plant Unit Info	789.0	26,290	4.5%	94.1%	4.8%	11,889			312,555	1,911,815	7.27	
17	<u>Manatee 2</u>												
18	Heavy Oil		6,476				11,492	11,628	6,399,999	74,419	878,973	13.57	75.59
19	Gas		17,722				11,492	203,673	1,000,000	203,673	948,314	5.35	4.66
20	Plant Unit Info	789.0	24,198	4.1%	94.1%	4.4%	11,492			278,092	1,827,287	7.55	
21	<u>Manatee 3</u>												
22	Gas		712,826				6,789	4,839,601	1,000,000	4,839,601	22,556,233	3.16	4.66
23	Plant Unit Info	1,223.0	712,826	78.3%	93.9%	83.4%	6,789			4,839,601	22,556,233	3.16	
24	<u>Manatee PV Solar</u>												
25	Solar		14,472					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,472	26.1%	N/A	26.1%	N/A						
27	<u>Martin 3</u>												
28	Gas		141,754				7,492	1,062,000	1,000,000	1,062,000	5,010,563	3.53	4.72
29	Plant Unit Info	464.0	141,754	41.1%	93.9%	43.7%	7,492			1,062,000	5,010,563	3.53	
30	<u>Martin 4</u>												
31	Gas		0					0	0	0	0	0.00	0.00
32	Plant Unit Info	464.0	0	N/A	N/A	N/A	N/A						
33	<u>Martin 8</u>												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		668,828				6,881	4,602,044	1,000,000	4,602,044	21,566,072	3.22	4.69

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	1,218.0	668,828	73.8%	93.5%	78.9%	6,881			4,602,044	21,566,072	3.22	
2	<u>Martin 8 Solar</u>												
3	Solar		9,114					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	55.0	9,114	22.3%	N/A	22.3%	N/A						
5	<u>Miami-Dade PV Solar</u>												
6	Solar		13,970					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,970	25.2%	N/A	25.2%	N/A						
8	<u>Nassau PV Solar</u>												
9	Solar		11,267					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	11,267	20.3%	N/A	20.3%	N/A						
11	<u>Northern Preserve ST Solar</u>												
12	Solar		12,992					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,992	23.4%	N/A	23.4%	N/A						
14	<u>OKEECHOBEE 1</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		1,009,824				6,294	6,355,798	1,000,000	6,355,798	31,162,706	3.09	4.90
17	Plant Unit Info	1,603.0	1,009,824	84.7%	93.0%	91.0%	6,294			6,355,798	31,162,706	3.09	
18	<u>Okeechobee PV Solar</u>												
19	Solar		14,662					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	14,662	26.5%	N/A	26.5%	N/A						
21	<u>Orange Blossom PV Solar</u>												
22	Solar		12,418					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,418	22.4%	N/A	22.4%	N/A						
24	<u>Palm Bay PV Solar</u>												
25	Solar		12,264					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,264	22.1%	N/A	22.1%	N/A						
27	<u>PEEC</u>												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		797,506				6,375	5,083,881	1,000,000	5,083,881	24,807,337	3.11	4.88
30	Plant Unit Info	1,254.0	797,506	85.5%	93.0%	91.9%	6,375			5,083,881	24,807,337	3.11	
31	<u>Pelican PV Solar</u>												
32	Solar		12,418					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	12,418	22.4%	N/A	22.4%	N/A						
34	<u>Pioneer Trail PV Solar</u>												
35	Solar		13,603					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	13,603	24.5%	N/A	24.5%	N/A						
2	<u>Riviera 5</u>												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		555,606				6,682	3,712,725	1,000,000	3,712,725	18,189,342	3.27	4.90
5	Plant Unit Info	1,308.0	555,606	57.1%	93.4%	61.1%	6,682			3,712,725	18,189,342	3.27	
6	<u>Rodeo PV Solar</u>												
7	Solar		12,810					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	12,810	23.1%	N/A	23.1%	N/A						
9	<u>Sabal Palm PV Solar</u>												
10	Solar		12,698					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	12,698	22.9%	N/A	22.9%	N/A						
12	<u>Sanford 4</u>												
13	Gas		55,103				7,158	394,431	1,000,000	394,431	1,935,523	3.51	4.91
14	Plant Unit Info	1,147.0	55,103	6.5%	16.7%	38.8%	7,158			394,431	1,935,523	3.51	
15	<u>Sanford 5</u>												
16	Gas		473,546				6,999	3,314,290	1,000,000	3,314,290	16,184,575	3.42	4.88
17	Plant Unit Info	1,147.0	473,546	55.5%	94.1%	59.0%	6,999			3,314,290	16,184,575	3.42	
18	<u>Scherer 4</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Coal		225,336				11,134	147,584	17,000,000	2,508,923	6,509,361	2.89	44.11
21	Plant Unit Info	636.0	225,336	47.6%	92.2%	51.7%	11,134			2,508,923	6,509,361	2.89	
22	<u>Southfork PV Solar</u>												
23	Solar		16,729					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	16,729	30.2%	N/A	30.2%	N/A						
25	<u>Space Coast</u>												
26	Solar		1,451					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10.0	1,451	19.5%	100.0%	19.5%	N/A						
28	<u>St Lucie 1</u>												
29	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,602,343	0.51	0.48
30	Plant Unit Info	981.0	711,586	97.5%	97.5%	100.0%	10,560			7,514,275	3,602,343	0.51	
31	<u>St Lucie 2</u>												
32	Nuclear		589,637				10,496	6,188,655	1,000,000	6,188,655	2,643,793	0.45	0.43
33	Plant Unit Info	840.0	589,637	94.3%	94.3%	100.0%	10,496			6,188,655	2,643,793	0.45	
34	<u>Sunshine Gateway PV Solar</u>												
35	Solar		14,347					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	14,347	25.9%	N/A	25.9%	N/A						
2	<u>Sweetbay PV Solar</u>												
3	Solar		13,027					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,027	23.5%	N/A	23.5%	N/A						
5	<u>Trailside PV Solar</u>												
6	Solar		11,968					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	11,968	21.6%	N/A	21.6%	N/A						
8	<u>Turkey Point 3</u>												
9	Nuclear		156,691				10,818	1,695,148	1,000,000	1,695,148	808,247	0.52	0.48
10	Plant Unit Info	837.0	156,691	23.3%	23.3%	100.0%	10,818			1,695,148	808,247	0.52	
11	<u>Turkey Point 4</u>												
12	Nuclear		612,238				10,729	6,568,514	1,000,000	6,568,514	3,889,874	0.64	0.59
13	Plant Unit Info	844.0	612,238	97.5%	97.5%	100.0%	10,729			6,568,514	3,889,874	0.64	
14	<u>Turkey Point 5</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		418,499				6,998	2,928,576	1,000,000	2,928,576	14,335,351	3.43	4.89
17	Plant Unit Info	1,256.0	418,499	44.8%	93.9%	47.7%	6,998			2,928,576	14,335,351	3.43	
18	<u>Twin Lakes ST Solar</u>												
19	Solar		13,886					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	13,886	25.1%	N/A	25.1%	N/A						
21	<u>Union Springs PV Solar</u>												
22	Solar		12,397					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,397	22.4%	N/A	22.4%	N/A						
24	<u>WCEC 01</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		263,800				6,820	1,799,207	1,000,000	1,799,207	8,401,623	3.18	4.67
27	Plant Unit Info	1,223.0	263,800	29.0%	46.4%	62.5%	6,820			1,799,207	8,401,623	3.18	
28	<u>WCEC 02</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Gas		661,589				6,696	4,429,979	1,000,000	4,429,979	20,649,779	3.12	4.66
31	Plant Unit Info	1,223.0	661,589	72.7%	87.3%	77.6%	6,696			4,429,979	20,649,779	3.12	
32	<u>WCEC 03</u>												
33	Light Oil		0				0	0	0	0	0	0.00	0.00
34	Gas		705,818				6,629	4,678,679	1,000,000	4,678,679	21,798,435	3.09	4.66
35	Plant Unit Info	1,228.0	705,818	77.3%	93.7%	88.5%	6,629			4,678,679	21,798,435	3.09	

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SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Wildflower PV Solar</u>												
2	Solar		15,474					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	15,474	27.9%	N/A	27.9%	N/A						
4	<u>Willow PV Solar</u>												
5	Solar		12,979					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	12,979	23.4%	N/A	23.4%	N/A						
7	<u>System Totals</u>												
8	Plant Unit Info	28,323	10,727,648				7,293			78,236,931	276,982,492	2.58	N/A
9	Total												
10													
11													
12													
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SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Nov - 2021												
2	<u>Babcock Preserve ST Solar</u>												
3	Solar		13,755					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,755	25.6%	N/A	25.6%	N/A						
5	<u>Babcock PV Solar</u>												
6	Solar		12,647					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,647	23.6%	N/A	23.6%	N/A						
8	<u>Barefoot PV Solar</u>												
9	Solar		12,750					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,750	23.8%	N/A	23.8%	N/A						
11	<u>Blue Cypress PV Solar</u>												
12	Solar		13,101					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,101	24.4%	N/A	24.4%	N/A						
14	<u>Blue Heron ST Solar</u>												
15	Solar		13,755					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,755	25.6%	N/A	25.6%	N/A						
17	<u>Cattle Ranch ST Solar</u>												
18	Solar		12,159					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	12,159	22.7%	N/A	22.7%	N/A						
20	<u>CCEC 3</u>												
21	Gas		480,140				6,665	3,200,121	1,000,000	3,200,121	16,764,123	3.49	5.24
22	Plant Unit Info	1,326.0	480,140	50.3%	93.4%	53.8%	6,665			3,200,121	16,764,123	3.49	
23	<u>Citrus PV Solar</u>												
24	Solar		12,570					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	12,570	23.4%	N/A	23.4%	N/A						
26	<u>Coral Farms PV Solar</u>												
27	Solar		13,212					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	13,212	24.6%	N/A	24.6%	N/A						
29	<u>Desoto Solar</u>												
30	Solar		3,261					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	25.0	3,261	18.1%	N/A	18.1%	N/A						
32	<u>Discovery PV Solar</u>												
33	Solar		10,194					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	10,194	19.0%	N/A	19.0%	N/A						
35	<u>Echo River PV Solar</u>												

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SCHEDULE E4

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		13,329					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	13,329	24.9%	N/A	24.9%	N/A						
3	<u>Egret PV Solar</u>												
4	Solar		9,806					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	9,806	18.3%	N/A	18.3%	N/A						
6	<u>Fort Drum PV Solar</u>												
7	Solar		9,979					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	9,979	18.6%	N/A	18.6%	N/A						
9	<u>Fort Myers 2</u>												
10	Gas		370,104				7,018	2,597,283	1,000,000	2,597,283	13,602,333	3.68	5.24
11	Plant Unit Info	1,740.0	370,104	29.5%	41.6%	71.1%	7,018			2,597,283	13,602,333	3.68	
12	<u>Fort Myers 3A</u>												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		3,432				10,930	37,512	1,000,000	37,512	197,550	5.76	5.27
15	Plant Unit Info	189.0	3,432	2.5%	77.1%	3.3%	10,930			37,512	197,550	5.76	
16	<u>Fort Myers 3B</u>												
17	Light Oil		0				0	0	0	0	0	0.00	0.00
18	Gas		2,895				10,942	31,677	1,000,000	31,677	166,982	5.77	5.27
19	Plant Unit Info	193.0	2,895	2.1%	77.1%	2.7%	10,942			31,677	166,982	5.77	
20	<u>Fort Myers 3C</u>												
21	Light Oil		0				0	0	0	0	0	0.00	0.00
22	Gas		3,066				10,555	32,363	1,000,000	32,363	170,312	5.55	5.26
23	Plant Unit Info	221.0	3,066	1.9%	77.1%	2.5%	10,555			32,363	170,312	5.55	
24	<u>Fort Myers 3D</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		3,066				10,555	32,363	1,000,000	32,363	170,312	5.55	5.26
27	Plant Unit Info	221.0	3,066	1.9%	77.1%	2.5%	10,555			32,363	170,312	5.55	
28	<u>Fort Myers GT</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
31	<u>Hammock PV Solar</u>												
32	Solar		14,053					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	14,053	26.2%	N/A	26.2%	N/A						
34	<u>Hibiscus PV Solar</u>												
35	Solar		12,211					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	12,211	22.8%	N/A	22.8%	N/A						
2	<u>Horizon PV Solar</u>												
3	Solar		13,335					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,335	24.9%	N/A	24.9%	N/A						
5	<u>Indian River PV Solar</u>												
6	Solar		13,089					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,089	24.4%	N/A	24.4%	N/A						
8	<u>Indiantown FPL</u>												
9	Coal											N/A	0.00
10	Gas		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
12	<u>Interstate PV Solar</u>												
13	Solar		12,422					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	74.5	12,422	23.2%	N/A	23.2%	N/A						
15	<u>Lakeside PV Solar</u>												
16	Solar		11,171					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	11,171	20.8%	N/A	20.8%	N/A						
18	<u>Lauderdale 1-12</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		0					0	0	0	0	0.00	0.00
21	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
22	<u>Lauderdale 6A</u>												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		3,938				10,721	42,220	1,000,000	42,220	221,851	5.63	5.25
25	Plant Unit Info	218.0	3,938	2.5%	94.0%	2.7%	10,721			42,220	221,851	5.63	
26	<u>Lauderdale 6B</u>												
27	Light Oil		0				0	0	0	0	0	0.00	0.00
28	Gas		4,050				10,590	42,890	1,000,000	42,890	225,633	5.57	5.26
29	Plant Unit Info	218.0	4,050	2.6%	94.0%	2.8%	10,590			42,890	225,633	5.57	
30	<u>Lauderdale 6C</u>												
31	Light Oil		0				0	0	0	0	0	0.00	0.00
32	Gas		3,938				10,721	42,220	1,000,000	42,220	222,574	5.65	5.27
33	Plant Unit Info	218.0	3,938	2.5%	94.0%	2.7%	10,721			42,220	222,574	5.65	
34	<u>Lauderdale 6D</u>												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		4,050				10,590	42,890	1,000,000	42,890	226,115	5.58	5.27
2	Plant Unit Info	218.0	4,050	2.6%	94.0%	2.8%	10,590			42,890	226,115	5.58	
3	<u>Lauderdale 6E</u>												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		3,938				10,721	42,220	1,000,000	42,220	222,333	5.65	5.27
6	Plant Unit Info	218.0	3,938	2.5%	94.0%	2.7%	10,721			42,220	222,333	5.65	
7	<u>Loggerhead PV Solar</u>												
8	Solar		13,286					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	13,286	24.8%	N/A	24.8%	N/A						
10	<u>Magnolia PV Solar</u>												
11	Solar		9,787					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	9,787	18.2%	N/A	18.2%	N/A						
13	<u>Manatee 1</u>												
14	Heavy Oil											N/A	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
17	<u>Manatee 2</u>												
18	Heavy Oil											N/A	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
21	<u>Manatee 3</u>												
22	Gas		619,062				6,843	4,236,431	1,000,000	4,236,431	21,972,884	3.55	5.19
23	Plant Unit Info	1,254.0	619,062	68.6%	93.9%	73.0%	6,843			4,236,431	21,972,884	3.55	
24	<u>Manatee PV Solar</u>												
25	Solar		12,714					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,714	23.7%	N/A	23.7%	N/A						
27	<u>Martin 3</u>												
28	Gas		37,842				7,941	300,495	1,000,000	300,495	1,565,108	4.14	5.21
29	Plant Unit Info	492.0	37,842	10.7%	93.9%	11.4%	7,941			300,495	1,565,108	4.14	
30	<u>Martin 4</u>												
31	Gas		0					0	0	0	0	0.00	0.00
32	Plant Unit Info	492.0	0	N/A	17.3%	N/A	N/A						
33	<u>Martin 8</u>												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		393,694				6,914	2,722,143	1,000,000	2,722,143	14,128,472	3.59	5.19

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	1,258.0	393,694	43.5%	93.5%	46.5%	6,914			2,722,143	14,128,472	3.59	
2	<u>Martin 8 Solar</u>												
3	Solar		6,510					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	55.0	6,510	16.4%	N/A	16.4%	N/A						
5	<u>Miami-Dade PV Solar</u>												
6	Solar		13,058					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,058	24.3%	N/A	24.3%	N/A						
8	<u>Nassau PV Solar</u>												
9	Solar		9,442					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	9,442	17.6%	N/A	17.6%	N/A						
11	<u>Northern Preserve ST Solar</u>												
12	Solar		11,955					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	11,955	22.3%	N/A	22.3%	N/A						
14	<u>OKEECHOBEE 1</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		699,312				6,357	4,445,575	1,000,000	4,445,575	23,468,770	3.36	5.28
17	Plant Unit Info	1,640.0	699,312	59.2%	69.7%	85.0%	6,357			4,445,575	23,468,770	3.36	
18	<u>Okeechobee PV Solar</u>												
19	Solar		12,724					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	12,724	23.7%	N/A	23.7%	N/A						
21	<u>Orange Blossom PV Solar</u>												
22	Solar		10,986					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	10,986	20.5%	N/A	20.5%	N/A						
24	<u>Palm Bay PV Solar</u>												
25	Solar		10,818					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	10,818	20.2%	N/A	20.2%	N/A						
27	<u>PEEC</u>												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		830,564				6,338	5,264,145	1,000,000	5,264,145	27,577,497	3.32	5.24
30	Plant Unit Info	1,283.0	830,564	89.9%	93.0%	96.7%	6,338			5,264,145	27,577,497	3.32	
31	<u>Pelican PV Solar</u>												
32	Solar		10,986					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	10,986	20.5%	N/A	20.5%	N/A						
34	<u>Pioneer Trail PV Solar</u>												
35	Solar		12,082					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	12,082	22.5%	N/A	22.5%	N/A						
2	<u>Riviera 5</u>												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		490,801				6,659	3,268,246	1,000,000	3,268,246	17,211,376	3.51	5.27
5	Plant Unit Info	1,326.0	490,801	51.4%	93.4%	55.0%	6,659			3,268,246	17,211,376	3.51	
6	<u>Rodeo PV Solar</u>												
7	Solar		10,751					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	10,751	20.0%	N/A	20.0%	N/A						
9	<u>Sabal Palm PV Solar</u>												
10	Solar		11,292					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	11,292	21.1%	N/A	21.1%	N/A						
12	<u>Sanford 4</u>												
13	Gas		104,810				7,017	735,453	1,000,000	735,453	3,862,387	3.69	5.25
14	Plant Unit Info	1,192.0	104,810	12.2%	94.1%	13.0%	7,017			735,453	3,862,387	3.69	
15	<u>Sanford 5</u>												
16	Gas		420,264				6,940	2,916,682	1,000,000	2,916,682	15,283,272	3.64	5.24
17	Plant Unit Info	1,192.0	420,264	49.0%	94.1%	52.1%	6,940			2,916,682	15,283,272	3.64	
18	<u>Scherer 4</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Coal		206,613				11,176	135,827	17,000,000	2,309,051	5,975,683	2.89	43.99
21	Plant Unit Info	626.0	206,613	45.8%	92.2%	49.7%	11,176			2,309,051	5,975,683	2.89	
22	<u>Southfork PV Solar</u>												
23	Solar		14,045					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	14,045	26.2%	N/A	26.2%	N/A						
25	<u>Space Coast</u>												
26	Solar		1,255					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10.0	1,255	17.4%	100.0%	17.4%	N/A						
28	<u>St Lucie 1</u>												
29	Nuclear		704,121				10,328	7,272,374	1,000,000	7,272,374	3,486,376	0.50	0.48
30	Plant Unit Info	1,003.0	704,121	97.5%	97.5%	100.0%	10,328			7,272,374	3,486,376	0.50	
31	<u>St Lucie 2</u>												
32	Nuclear		603,399				10,257	6,188,882	1,000,000	6,188,882	2,643,891	0.44	0.43
33	Plant Unit Info	859.6	603,399	97.5%	97.5%	100.0%	10,257			6,188,882	2,643,891	0.44	
34	<u>Sunshine Gateway PV Solar</u>												
35	Solar		12,701					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	12,701	23.7%	N/A	23.7%	N/A						
2	<u>Sweetbay PV Solar</u>												
3	Solar		11,706					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	11,706	21.8%	N/A	21.8%	N/A						
5	<u>Trailside PV Solar</u>												
6	Solar		9,753					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	9,753	18.2%	N/A	18.2%	N/A						
8	<u>Turkey Point 3</u>												
9	Nuclear		482,400				10,541	5,085,123	1,000,000	5,085,123	2,522,730	0.52	0.50
10	Plant Unit Info	859.0	482,400	77.5%	77.5%	100.0%	10,541			5,085,123	2,522,730	0.52	
11	<u>Turkey Point 4</u>												
12	Nuclear		607,968				10,456	6,356,974	1,000,000	6,356,974	3,764,600	0.62	0.59
13	Plant Unit Info	866.0	607,968	97.5%	97.5%	100.0%	10,456			6,356,974	3,764,600	0.62	
14	<u>Turkey Point 5</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		215,557				6,900	1,487,404	1,000,000	1,487,404	7,805,437	3.62	5.25
17	Plant Unit Info	1,294.0	215,557	23.1%	68.9%	33.6%	6,900			1,487,404	7,805,437	3.62	
18	<u>Twin Lakes ST Solar</u>												
19	Solar		11,832					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	11,832	22.1%	N/A	22.1%	N/A						
21	<u>Union Springs PV Solar</u>												
22	Solar		9,899					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	9,899	18.5%	N/A	18.5%	N/A						
24	<u>WCEC 01</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		441,856				6,777	2,994,267	1,000,000	2,994,267	15,534,325	3.52	5.19
27	Plant Unit Info	1,248.0	441,856	49.2%	93.7%	52.5%	6,777			2,994,267	15,534,325	3.52	
28	<u>WCEC 02</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Gas		554,347				6,725	3,728,048	1,000,000	3,728,048	19,337,279	3.49	5.19
31	Plant Unit Info	1,248.0	554,347	61.7%	60.4%	65.8%	6,725			3,728,048	19,337,279	3.49	
32	<u>WCEC 03</u>												
33	Light Oil		0				0	0	0	0	0	0.00	0.00
34	Gas		465,195				6,669	3,102,330	1,000,000	3,102,330	16,092,104	3.46	5.19
35	Plant Unit Info	1,254.0	465,195	51.5%	93.7%	85.3%	6,669			3,102,330	16,092,104	3.46	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Wildflower PV Solar</u>												
2	Solar		13,864					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	13,864	25.9%	N/A	25.9%	N/A						
4	<u>Willow PV Solar</u>												
5	Solar		11,131					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	11,131	20.8%	N/A	20.8%	N/A						
7	<u>System Totals</u>												
8	Plant Unit Info	28,956	9,239,798				7,420			68,557,382	234,422,308	2.54	N/A
9	Total												
10													
11													
12													
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Dec - 2021</u>												
2	<u>Babcock Preserve ST Solar</u>												
3	Solar		12,564					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,564	22.7%	N/A	22.7%	N/A						
5	<u>Babcock PV Solar</u>												
6	Solar		11,786					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	11,786	21.3%	N/A	21.3%	N/A						
8	<u>Barefoot PV Solar</u>												
9	Solar		11,620					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	11,620	21.0%	N/A	21.0%	N/A						
11	<u>Blue Cypress PV Solar</u>												
12	Solar		12,043					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,043	21.7%	N/A	21.7%	N/A						
14	<u>Blue Heron ST Solar</u>												
15	Solar		12,564					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,564	22.7%	N/A	22.7%	N/A						
17	<u>Cattle Ranch ST Solar</u>												
18	Solar		10,595					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	10,595	19.1%	N/A	19.1%	N/A						
20	<u>CCEC 3</u>												
21	Gas		382,126				6,726	2,570,008	1,000,000	2,570,008	14,154,952	3.70	5.51
22	Plant Unit Info	1,326.0	382,126	38.7%	93.4%	41.5%	6,726			2,570,008	14,154,952	3.70	
23	<u>Citrus PV Solar</u>												
24	Solar		11,757					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	11,757	21.2%	N/A	21.2%	N/A						
26	<u>Coral Farms PV Solar</u>												
27	Solar		12,061					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	12,061	21.8%	N/A	21.8%	N/A						
29	<u>Desoto Solar</u>												
30	Solar		2,906					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	25.0	2,906	15.6%	N/A	15.6%	N/A						
32	<u>Discovery PV Solar</u>												
33	Solar		9,342					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	9,342	16.9%	N/A	16.9%	N/A						
35	<u>Echo River PV Solar</u>												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		10,814					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	10,814	19.5%	N/A	19.5%	N/A						
3	<u>Egret PV Solar</u>												
4	Solar		8,172					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	8,172	14.7%	N/A	14.7%	N/A						
6	<u>Fort Drum PV Solar</u>												
7	Solar		9,111					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	9,111	16.4%	N/A	16.4%	N/A						
9	<u>Fort Myers 2</u>												
10	Gas		766,022				6,994	5,357,916	1,000,000	5,357,916	29,503,762	3.85	5.51
11	Plant Unit Info	1,740.0	766,022	59.2%	84.7%	69.9%	6,994			5,357,916	29,503,762	3.85	
12	<u>Fort Myers 3A</u>												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	189.0	0	N/A	93.8%	N/A	N/A						
16	<u>Fort Myers 3B</u>												
17	Light Oil		0				0	0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	193.0	0	N/A	93.8%	N/A	N/A						
20	<u>Fort Myers 3C</u>												
21	Light Oil		0				0	0	0	0	0	0.00	0.00
22	Gas		1,930				10,825	20,892	1,000,000	20,892	115,161	5.97	5.51
23	Plant Unit Info	221.0	1,930	1.2%	93.8%	1.3%	10,825			20,892	115,161	5.97	
24	<u>Fort Myers 3D</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		3,974				10,686	42,468	1,000,000	42,468	234,321	5.90	5.52
27	Plant Unit Info	221.0	3,974	2.4%	93.8%	2.6%	10,686			42,468	234,321	5.90	
28	<u>Fort Myers GT</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
31	<u>Hammock PV Solar</u>												
32	Solar		12,892					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	12,892	23.3%	N/A	23.3%	N/A						
34	<u>Hibiscus PV Solar</u>												
35	Solar		11,247					N/A	N/A	N/A	N/A	N/A	N/A

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	11,247	20.3%	N/A	20.3%	N/A						
2	<u>Horizon PV Solar</u>												
3	Solar		12,148					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,148	21.9%	N/A	21.9%	N/A						
5	<u>Indian River PV Solar</u>												
6	Solar		12,031					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,031	21.7%	N/A	21.7%	N/A						
8	<u>Indiantown FPL</u>												
9	Coal											N/A	0.00
10	Gas		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
12	<u>Interstate PV Solar</u>												
13	Solar		11,611					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	74.5	11,611	21.0%	N/A	21.0%	N/A						
15	<u>Lakeside PV Solar</u>												
16	Solar		10,447					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	10,447	18.9%	N/A	18.9%	N/A						
18	<u>Lauderdale 1-12</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		0					0	0	0	0	0.00	0.00
21	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
22	<u>Lauderdale 6A</u>												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		1,013				10,585	10,723	1,000,000	10,723	59,137	5.84	5.51
25	Plant Unit Info	218.0	1,013	0.6%	94.0%	0.7%	10,585			10,723	59,137	5.84	
26	<u>Lauderdale 6B</u>												
27	Light Oil		0				0	0	0	0	0	0.00	0.00
28	Gas		1,005				10,626	10,679	1,000,000	10,679	58,848	5.86	5.51
29	Plant Unit Info	218.0	1,005	0.6%	94.0%	0.7%	10,626			10,679	58,848	5.86	
30	<u>Lauderdale 6C</u>												
31	Light Oil		0				0	0	0	0	0	0.00	0.00
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
34	<u>Lauderdale 6D</u>												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		1,013				10,585	10,723	1,000,000	10,723	59,137	5.84	5.51
2	Plant Unit Info	218.0	1,013	0.6%	94.0%	0.7%	10,585			10,723	59,137	5.84	
3	<u>Lauderdale 6E</u>												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
7	<u>Loggerhead PV Solar</u>												
8	Solar		12,343					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	12,343	22.3%	N/A	22.3%	N/A						
10	<u>Magnolia PV Solar</u>												
11	Solar		8,228					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	8,228	14.8%	N/A	14.8%	N/A						
13	<u>Manatee 1</u>												
14	Heavy Oil											N/A	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
17	<u>Manatee 2</u>												
18	Heavy Oil											N/A	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
21	<u>Manatee 3</u>												
22	Gas		242,391				6,946	1,683,575	1,000,000	1,683,575	9,183,889	3.79	5.45
23	Plant Unit Info	1,254.0	242,391	26.0%	48.7%	53.3%	6,946			1,683,575	9,183,889	3.79	
24	<u>Manatee PV Solar</u>												
25	Solar		11,751					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	11,751	21.2%	N/A	21.2%	N/A						
27	<u>Martin 3</u>												
28	Gas		175,305				7,361	1,290,437	1,000,000	1,290,437	7,040,168	4.02	5.46
29	Plant Unit Info	492.0	175,305	47.9%	93.9%	51.0%	7,361			1,290,437	7,040,168	4.02	
30	<u>Martin 4</u>												
31	Gas		24,817				7,939	197,025	1,000,000	197,025	1,074,770	4.33	5.45
32	Plant Unit Info	492.0	24,817	6.8%	93.9%	7.2%	7,939			197,025	1,074,770	4.33	
33	<u>Martin 8</u>												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		249,682				7,021	1,753,103	1,000,000	1,753,103	9,564,305	3.83	5.46

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	1,258.0	249,682	26.7%	93.5%	28.5%	7,021			1,753,103	9,564,305	3.83	
2	<u>Martin 8 Solar</u>												
3	Solar		5,425					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	55.0	5,425	13.3%	N/A	13.3%	N/A						
5	<u>Miami-Dade PV Solar</u>												
6	Solar		12,413					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,413	22.4%	N/A	22.4%	N/A						
8	<u>Nassau PV Solar</u>												
9	Solar		7,747					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	7,747	14.0%	N/A	14.0%	N/A						
11	<u>Northern Preserve ST Solar</u>												
12	Solar		10,920					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	10,920	19.7%	N/A	19.7%	N/A						
14	<u>OKEECHOBEE 1</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		723,915				6,376	4,615,472	1,000,000	4,615,472	25,456,754	3.52	5.52
17	Plant Unit Info	1,640.0	723,915	59.3%	77.9%	76.1%	6,376			4,615,472	25,456,754	3.52	
18	<u>Okeechobee PV Solar</u>												
19	Solar		11,539					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	11,539	20.8%	N/A	20.8%	N/A						
21	<u>Orange Blossom PV Solar</u>												
22	Solar		10,031					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	10,031	18.1%	N/A	18.1%	N/A						
24	<u>Palm Bay PV Solar</u>												
25	Solar		9,871					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	9,871	17.8%	N/A	17.8%	N/A						
27	<u>PEEC</u>												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		753,501				6,429	4,844,420	1,000,000	4,844,420	26,675,898	3.54	5.51
30	Plant Unit Info	1,283.0	753,501	78.9%	93.0%	84.9%	6,429			4,844,420	26,675,898	3.54	
31	<u>Pelican PV Solar</u>												
32	Solar		10,031					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	10,031	18.1%	N/A	18.1%	N/A						
34	<u>Pioneer Trail PV Solar</u>												
35	Solar		11,197					N/A	N/A	N/A	N/A	N/A	N/A

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SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capacity (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	11,197	20.2%	N/A	20.2%	N/A						
2	<u>Riviera 5</u>												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		503,844				6,660	3,355,850	1,000,000	3,355,850	18,509,278	3.67	5.52
5	Plant Unit Info	1,326.0	503,844	51.1%	93.4%	54.7%	6,660			3,355,850	18,509,278	3.67	
6	<u>Rodeo PV Solar</u>												
7	Solar		9,474					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	9,474	17.1%	N/A	17.1%	N/A						
9	<u>Sabal Palm PV Solar</u>												
10	Solar		10,439					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	10,439	18.8%	N/A	18.8%	N/A						
12	<u>Sanford 4</u>												
13	Gas		55,435				7,547	418,343	1,000,000	418,343	2,306,575	4.16	5.51
14	Plant Unit Info	1,192.0	55,435	6.3%	94.1%	6.6%	7,547			418,343	2,306,575	4.16	
15	<u>Sanford 5</u>												
16	Gas		430,020				6,948	2,987,957	1,000,000	2,987,957	16,452,796	3.83	5.51
17	Plant Unit Info	1,192.0	430,020	48.5%	94.1%	51.5%	6,948			2,987,957	16,452,796	3.83	
18	<u>Scherer 4</u>												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Coal		216,006				11,157	141,762	17,000,000	2,409,946	6,234,535	2.89	43.98
21	Plant Unit Info	626.0	216,006	46.4%	92.2%	50.3%	11,157			2,409,946	6,234,535	2.89	
22	<u>Southfork PV Solar</u>												
23	Solar		12,295					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	12,295	22.2%	N/A	22.2%	N/A						
25	<u>Space Coast</u>												
26	Solar		1,170					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10.0	1,170	15.7%	100.0%	15.7%	N/A						
28	<u>St Lucie 1</u>												
29	Nuclear		727,591				10,328	7,514,787	1,000,000	7,514,787	3,654,441	0.50	0.49
30	Plant Unit Info	1,003.0	727,591	97.5%	97.5%	100.0%	10,328			7,514,787	3,654,441	0.50	
31	<u>St Lucie 2</u>												
32	Nuclear		623,512				10,257	6,395,178	1,000,000	6,395,178	2,732,020	0.44	0.43
33	Plant Unit Info	859.6	623,512	97.5%	97.5%	100.0%	10,257			6,395,178	2,732,020	0.44	
34	<u>Sunshine Gateway PV Solar</u>												
35	Solar		10,864					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	74.5	10,864	19.6%	N/A	19.6%	N/A						
2	<u>Sweetbay PV Solar</u>												
3	Solar		10,858					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	10,858	19.6%	N/A	19.6%	N/A						
5	<u>Trailside PV Solar</u>												
6	Solar		8,552					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	8,552	15.4%	N/A	15.4%	N/A						
8	<u>Turkey Point 3</u>												
9	Nuclear		623,100				10,541	6,568,284	1,000,000	6,568,284	3,258,526	0.52	0.50
10	Plant Unit Info	859.0	623,100	97.5%	97.5%	100.0%	10,541			6,568,284	3,258,526	0.52	
11	<u>Turkey Point 4</u>												
12	Nuclear		628,234				10,456	6,568,874	1,000,000	6,568,874	3,890,087	0.62	0.59
13	Plant Unit Info	866.0	628,234	97.5%	97.5%	100.0%	10,456			6,568,874	3,890,087	0.62	
14	<u>Turkey Point 5</u>												
15	Light Oil		0				0	0	0	0	0	0.00	0.00
16	Gas		475,174				6,871	3,264,879	1,000,000	3,264,879	17,977,112	3.78	5.51
17	Plant Unit Info	1,294.0	475,174	49.4%	73.0%	67.6%	6,871			3,264,879	17,977,112	3.78	
18	<u>Twin Lakes ST Solar</u>												
19	Solar		10,310					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	10,310	18.6%	N/A	18.6%	N/A						
21	<u>Union Springs PV Solar</u>												
22	Solar		8,322					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	8,322	15.0%	N/A	15.0%	N/A						
24	<u>WCEC 01</u>												
25	Light Oil		0				0	0	0	0	0	0.00	0.00
26	Gas		284,153				6,884	1,956,072	1,000,000	1,956,072	10,670,360	3.76	5.45
27	Plant Unit Info	1,248.0	284,153	30.6%	93.7%	32.7%	6,884			1,956,072	10,670,360	3.76	
28	<u>WCEC 02</u>												
29	Light Oil		0				0	0	0	0	0	0.00	0.00
30	Gas		472,360				6,776	3,200,565	1,000,000	3,200,565	17,459,060	3.70	5.45
31	Plant Unit Info	1,248.0	472,360	50.9%	56.1%	54.3%	6,776			3,200,565	17,459,060	3.70	
32	<u>WCEC 03</u>												
33	Light Oil		0				0	0	0	0	0	0.00	0.00
34	Gas		331,568				6,761	2,241,714	1,000,000	2,241,714	12,228,534	3.69	5.45
35	Plant Unit Info	1,254.0	331,568	35.5%	93.7%	63.4%	6,761			2,241,714	12,228,534	3.69	

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E4	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Wildflower PV Solar</u>												
2	Solar		12,684					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	12,684	22.9%	N/A	22.9%	N/A						
4	<u>Willow PV Solar</u>												
5	Solar		9,726					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	9,726	17.6%	N/A	17.6%	N/A						
7	<u>System Totals</u>												
8	Plant Unit Info	28,956	9,129,592				7,590			69,289,890	238,554,425	2.61	N/A
9	Total												
10													
11													
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FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

Docket No. 20210001-EI
2021 FCR Actual Estimated
Exhibit RBD-3, Page 53 of 57
SCHEDULE E5

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Fuel Type	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021
#6 Heavy Oil (BBLs)						
Purchases						
Units	132,000					
Unit Cost	84.1997					
Amount	11,114,358					
Burned						
Units	11,936	25,203	35,680	21,598		
Unit Cost	75.5913	75.5913	75.5913	75.5913		
Amount	902,253	1,905,102	2,697,063	1,632,595		
Ending Inventory						
Units	556,954	531,751	496,072	474,474	474,474	474,474
Unit Cost	75.5913	75.5913	75.5913	75.5913	75.5913	75.5913
Amount	42,100,888	40,195,786	37,498,723	35,866,128	35,866,128	35,866,128
#2 Light Oil (BBLs)						
Purchases						
Units			35,559			
Unit Cost			95.3817			
Amount			3,391,666			
Burned						
Units	4,066	5,725	18,075	7,472		
Unit Cost	76.3717	76.3716	81.2418	94.6781		
Amount	310,544	437,218	1,468,413	707,422		
Ending Inventory						
Units	1,358,122	1,352,397	1,369,881	1,362,409	1,362,409	1,362,409
Unit Cost	92.0953	92.1619	92.3895	92.3770	92.3770	92.3770
Amount	125,076,631	124,639,412	126,562,665	125,855,242	125,855,242	125,855,242
Coal						
Purchases						
Units	2,500,000	2,500,000	2,500,000	1,750,000	1,300,000	1,107,395
Unit Cost	2.5557	2.5717	2.5621	2.5668	2.5763	2.5859
Amount	6,389,250	6,429,250	6,405,250	4,491,900	3,349,190	2,863,613
Burned						
Units	2,735,886	2,846,705	2,746,710	2,508,923	2,309,051	2,409,946
Unit Cost	2.6976	2.6466	2.6103	2.5945	2.5879	2.5870
Amount	7,380,430	7,533,974	7,169,634	6,509,361	5,975,683	6,234,535
Ending Inventory						
Units	3,663,940	3,317,235	3,070,525	2,311,602	1,302,551	
Unit Cost	2.6976	2.6466	2.6103	2.5945	2.5879	0.0000
Amount	9,883,984	8,779,260	8,014,876	5,997,415	3,370,922	0
Gas (MCF)						
Burned						
Units	60,083,906	62,145,548	60,028,536	53,579,630	41,344,978	39,832,821
Unit Cost	4.6299	4.6277	4.5981	4.8001	5.2250	5.4926
Amount	278,184,905	287,591,402	276,014,871	257,188,857	216,029,029	218,784,816
Nuclear (Other)						
Burned						
Units	27,046,432	26,221,278	19,985,311	21,966,592	24,903,353	27,047,123
Unit Cost	0.4958	0.4977	0.5145	0.4982	0.4986	0.5004
Amount	13,409,810	13,050,373	10,281,457	10,944,257	12,417,597	13,535,074

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
POWER SOLD

SCHEDULE E6

ESTIMATED FOR THE PERIOD OF: JULY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Power Sold To / Purchased From	Type & Schedule	Total KWH Sold (000)	KWH from Own Generation (000)	Fuel Cost (cents/KWH)	Total Cost (cents/KWH)	Total \$ for Fuel Adj	Total Cost (\$)	Gain from Off System Sales (\$)
1	<u>Jul - 2021</u>								
2	Off System	OS	141,980	141,980	2.451	3.830	3,480,379	5,437,854	1,458,759
3	St Lucie Reliability Sales	OS	52,997	52,997	0.495	0.495	262,374	262,374	
4	Subtotal Jul - 2021		194,977	194,977	1.920	2.924	3,742,753	5,700,228	1,458,759
5									
6	<u>Aug - 2021</u>								
7	Off System	OS	147,250	147,250	2.590	3.918	3,813,806	5,769,058	1,410,502
8	St Lucie Reliability Sales	OS	52,997	52,997	0.495	0.495	262,374	262,374	
9	Subtotal Aug - 2021		200,247	200,247	2.036	3.012	4,076,180	6,031,432	1,410,502
10									
11	<u>Sep - 2021</u>								
12	Off System	OS	137,100	137,100	2.720	4.099	3,728,646	5,619,961	1,366,865
13	St Lucie Reliability Sales	OS	51,287	51,287	0.495	0.495	253,910	253,910	
14	Subtotal Sep - 2021		188,387	188,387	2.114	3.118	3,982,556	5,873,872	1,366,865
15									
16	<u>Oct - 2021</u>								
17	Off System	OS	137,640	137,640	2.418	3.637	3,328,033	5,006,134	1,368,411
18	St Lucie Reliability Sales	OS	52,997	52,997	0.495	0.495	262,374	262,374	
19	Subtotal Oct - 2021		190,637	190,637	1.883	2.764	3,590,407	5,268,507	1,368,411
20									
21	<u>Nov - 2021</u>								
22	Off System	OS	218,100	218,100	2.122	3.154	4,628,517	6,879,620	1,705,853
23	St Lucie Reliability Sales	OS	52,441	52,441	0.484	0.484	253,927	253,927	
24	Subtotal Nov - 2021		270,541	270,541	1.805	2.637	4,882,444	7,133,548	1,705,853
25									
26	<u>Dec - 2021</u>								
27	Off System	OS	205,530	205,530	2.230	3.326	4,583,496	6,836,545	1,636,460
28	St Lucie Reliability Sales	OS	54,189	54,189	0.484	0.484	262,392	262,392	
29	Subtotal Dec - 2021		259,719	259,719	1.866	2.733	4,845,887	7,098,937	1,636,460
30									
31	<u>2021</u>								
32	Off System	OS	987,600	987,600	2.386	3.600	23,562,877	35,549,172	8,946,850
33	St Lucie Reliability Sales	OS	316,909	316,909	0.491	0.491	1,557,351	1,557,351	
34	Subtotal 2021		1,304,509	1,304,509	1.926	2.844	25,120,228	37,106,523	8,946,850

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE E7

ESTIMATED FOR THE PERIOD OF: JULY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Estimated Power Purchases	KWH Purchased (000)	KWH for Firm	Fuel Cost (cents/KWH)	Total \$ for Fuel Adj
1	<u>Jul - 2021</u>				
2	St Lucie Reliability	53,320	53,320	0.456	242,873
3	SWA	76,215	76,215	3.326	2,534,733
4	Subtotal Jul - 2021	129,535	129,535	2.144	2,777,606
5					
6	<u>Aug - 2021</u>				
7	St Lucie Reliability	40,298	40,298	0.456	183,558
8	SWA	75,166	75,166	3.425	2,574,777
9	Subtotal Aug - 2021	115,464	115,464	2.389	2,758,335
10					
11	<u>Sep - 2021</u>				
12	SWA	68,357	68,357	3.442	2,353,189
13	Subtotal Sep - 2021	68,357	68,357	3.442	2,353,189
14					
15	<u>Oct - 2021</u>				
16	St Lucie Reliability	49,898	49,898	0.491	245,044
17	SWA	66,402	66,402	3.335	2,214,645
18	Subtotal Oct - 2021	116,300	116,300	2.115	2,459,689
19					
20	<u>Nov - 2021</u>				
21	St Lucie Reliability	52,808	52,808	0.480	253,429
22	SWA	68,544	68,544	3.469	2,378,114
23	Subtotal Nov - 2021	121,352	121,352	2.169	2,631,543
24					
25	<u>Dec - 2021</u>				
26	St Lucie Reliability	54,568	54,568	0.480	261,877
27	SWA	79,117	79,117	3.284	2,597,925
28	Subtotal Dec - 2021	133,685	133,685	2.139	2,859,802
29					
30	<u>2021</u>				
31	St Lucie Reliability	250,892	250,892	0.473	1,186,781
32	SWA	433,801	433,801	3.378	14,653,383
33	Subtotal 2021	684,693	684,693	2.313	15,840,164
34					

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ENERGY PAYMENT TO QUALIFYING FACILITIES

SCHEDULE E8

ESTIMATED FOR THE PERIOD OF: JULY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Estimated Payments	Total KWH Purchased (000)	KWH for Firm (000)	Fuel Cost (cents/KWH)	Total \$ for Fuel Adj
1	<u>Jul - 2021</u>				
2	Qualifying Facilities	23,443	23,443	2.320	543,844
3	Subtotal Jul - 2021	23,443	23,443	2.320	543,844
4					
5	<u>Aug - 2021</u>				
6	Qualifying Facilities	19,277	19,277	2.464	474,917
7	Subtotal Aug - 2021	19,277	19,277	2.464	474,917
8					
9	<u>Sep - 2021</u>				
10	Qualifying Facilities	25,546	25,546	2.462	628,902
11	Subtotal Sep - 2021	25,546	25,546	2.462	628,902
12					
13	<u>Oct - 2021</u>				
14	Qualifying Facilities	21,561	21,561	2.465	531,444
15	Subtotal Oct - 2021	21,561	21,561	2.465	531,444
16					
17	<u>Nov - 2021</u>				
18	Qualifying Facilities	25,934	25,934	2.212	573,623
19	Subtotal Nov - 2021	25,934	25,934	2.212	573,623
20					
21	<u>Dec - 2021</u>				
22	Qualifying Facilities	26,844	26,844	2.284	613,145
23	Subtotal Dec - 2021	26,844	26,844	2.284	613,145
24					
25	<u>2021</u>				
26	Qualifying Facilities	142,605	142,605	2.360	3,365,875
27	Subtotal 2021	142,605	142,605	2.360	3,365,875
28					

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ECONOMY ENERGY PURCHASES

SCHEDULE E9

ESTIMATED FOR THE PERIOD OF: JULY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Estimated Purchases	Type	Total KWH Purchase (000)	Transaction Cost (cents/kWh)	Total \$ for Fuel Adj	Cost if Generated (cents/kWh)	Cost if Generated (\$)	Fuel Savings (\$)
1	<u>Jul - 2021</u>							
2	Economy	OS	44,020	3.000	1,320,600	3.24	1,424,565	103,965
3	Subtotal Jul - 2021		44,020	3.000	1,320,600	3.24	1,424,565	103,965
4								
5	<u>Aug - 2021</u>							
6	Economy	OS	16,430	3.000	492,900	3.66	601,059	108,159
7	Subtotal Aug - 2021		16,430	3.000	492,900	3.66	601,059	108,159
8								
9	<u>Sep - 2021</u>							
10	Economy	OS	50,400	2.850	1,436,400	3.62	1,826,076	389,676
11	Subtotal Sep - 2021		50,400	2.850	1,436,400	3.62	1,826,076	389,676
12								
13	<u>Oct - 2021</u>							
14	Economy	OS	43,400	2.750	1,193,500	3.16	1,369,794	176,294
15	Subtotal Oct - 2021		43,400	2.750	1,193,500	3.16	1,369,794	176,294
16								
17	<u>Nov - 2021</u>							
18	Economy	OS	0					
19	Subtotal Nov - 2021		0					
20								
21	<u>Dec - 2021</u>							
22	Economy	OS	0					
23	Subtotal Dec - 2021		0					
24								
25	<u>2021</u>							
26	Economy	OS	154,250	2.881	4,443,400	3.39	5,221,494	778,094
27	Subtotal 2021		154,250	2.881	4,443,400	3.39	5,221,494	778,094
28								

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Calculation of Actual/Estimated True-Up Amount

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Base													
2	Payments to Non-cogenerators	\$1,317,600	\$1,317,600	\$1,317,600	\$1,317,600	\$1,317,600	\$1,364,000	\$1,364,000	\$1,364,000	\$1,364,000	\$1,364,000	\$1,364,000	\$1,364,000	\$16,136,000
3	Payments to Co-generators	\$122,325	\$122,325	\$122,325	\$122,325	\$122,325	\$122,325	\$122,325	\$122,325	\$122,325	\$122,325	\$122,325	\$122,325	\$1,467,900
4	Transmission of Electricity by Others	(\$381,453)	\$383,741	\$5,042	\$8,736	\$19,663	-	\$15,777	\$2,023	\$23,796	\$30,118	\$35,624	\$19,544	\$162,610
5	Transmission Revenues from Capacity Sales	(\$1,522,301)	(\$1,527,257)	(\$418,937)	(\$431,660)	(\$883,463)	(\$856,681)	(\$498,715)	(\$544,750)	(\$524,450)	(\$309,690)	(\$545,250)	(\$616,590)	(\$8,679,744)
6	Incremental Plant Security Costs O&M	\$2,444,301	\$2,010,330	\$2,502,706	\$2,122,535	\$2,095,925	\$2,169,543	\$2,450,471	\$2,350,323	\$2,239,301	\$2,661,211	\$2,355,299	\$3,131,207	\$28,533,153
7	Incremental Plant Security Costs Capital	\$376,871	\$375,919	\$374,913	\$374,047	\$373,232	\$372,125	\$371,502	\$371,173	\$372,927	\$374,681	\$377,987	\$385,112	\$4,500,490
8	Incremental Nuclear NRC Compliance Costs O&M	\$29,908	\$52,466	\$317,253	\$91,676	\$94,054	\$53,021	\$75,306	\$75,338	\$75,330	\$74,730	\$65,206	\$67,714	\$1,072,001
9	Incremental Nuclear NRC Compliance Costs Capital	\$1,056,851	\$1,056,002	\$1,056,572	\$1,064,242	\$1,069,928	\$1,067,780	\$1,065,466	\$1,062,634	\$1,059,802	\$1,060,023	\$1,052,807	\$1,035,770	\$12,707,875
10	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	\$9,038,259	\$9,007,261	\$8,976,263	\$8,945,265	\$8,914,267	\$8,883,268	\$8,852,270	\$8,821,272	\$8,790,274	\$8,759,276	\$8,728,278	\$8,697,280	\$106,413,233
11	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	(\$80,153)	(\$79,747)	(\$79,341)	(\$78,935)	(\$78,529)	(\$78,123)	(\$77,717)	(\$77,311)	(\$76,905)	(\$76,499)	(\$76,093)	(\$75,687)	(\$935,041)
12	Indiantown Transaction - Regulatory Asset - Amortization and Return	\$5,839,699	\$5,811,815	\$5,783,930	\$5,756,045	\$5,728,160	\$5,700,275	\$5,672,391	\$5,644,506	\$5,616,621	\$5,588,736	\$5,560,852	\$5,532,967	\$68,235,997
13	SJRPP Transaction Revenue Requirements	\$723,705	\$712,033	\$700,361	\$688,689	\$677,017	\$665,345	\$653,673	\$642,001	\$630,329	\$618,657	-	-	\$6,711,807
14	Subtotal Base	\$18,965,613	\$19,242,486	\$20,658,686	\$19,980,564	\$19,450,179	\$19,462,879	\$20,066,748	\$19,833,535	\$19,693,349	\$20,267,568	\$19,041,033	\$19,663,641	\$236,326,282
15														
16	General													
17	Incremental Plant Security Costs Capital	\$1,090	(\$16)	(\$16)	(\$2,408)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,349)
18	Subtotal General	\$1,090	(\$16)	(\$16)	(\$2,408)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,349)
19														
20	Intermediate													
21	Incremental Plant Security Costs O&M	\$299,399	\$323,444	\$278,084	\$297,526	\$216,322	\$168,544	\$693,876	\$395,395	\$310,929	\$966,281	\$683,058	\$368,412	\$5,001,268
22	Incremental Plant Security Costs Capital	\$53,544	\$54,085	\$56,356	\$61,615	\$65,065	\$65,390	\$65,751	\$65,905	\$66,350	\$67,018	\$67,393	\$67,251	\$755,723
23	Subtotal Intermediate	\$352,944	\$377,529	\$334,440	\$359,141	\$281,387	\$233,934	\$759,627	\$461,300	\$377,279	\$1,033,298	\$750,450	\$435,663	\$5,756,991
24														
25	Peaking													
26	Incremental Plant Security Costs O&M	\$25,376	\$22,743	\$24,770	\$31,327	\$31,649	\$26,811	\$16,941	\$36,973	\$36,964	\$39,698	\$27,004	\$27,097	\$347,354
27	Incremental Plant Security Costs Capital	\$6,432	\$6,525	\$6,617	\$6,596	\$6,575	\$6,555	\$6,534	\$6,513	\$6,492	\$6,471	\$6,451	\$6,430	\$78,191
28	Subtotal Peaking	\$31,808	\$29,268	\$31,387	\$37,923	\$38,225	\$33,366	\$23,475	\$43,486	\$43,456	\$46,170	\$33,455	\$33,527	\$425,545
29														
30	Solar													
31	Incremental Plant Security Costs O&M	\$21,404	\$337	\$9,814	\$6,528	\$9,006	\$1,062	-	-	-	\$4,991	\$64,950	(\$3,764)	\$114,328
32	Incremental Plant Security Costs Capital	\$6,017	\$6,008	\$6,012	\$5,976	\$5,947	\$5,921	\$5,894	\$5,868	\$5,842	\$5,816	\$5,790	\$5,763	\$70,854
33	Subtotal Solar	\$27,422	\$6,346	\$15,826	\$12,504	\$14,952	\$6,983	\$5,894	\$5,868	\$5,842	\$10,807	\$70,739	\$1,999	\$185,182
34														
35	Total	\$19,378,877	\$19,655,612	\$21,040,322	\$20,387,724	\$19,784,744	\$19,737,161	\$20,855,744	\$20,344,188	\$20,119,927	\$21,357,844	\$19,895,678	\$20,134,830	\$242,692,650

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Calculation of Actual/Estimated True-Up Amount

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1														
2	Total Capacity Costs	\$19,378,877	\$19,655,612	\$21,040,322	\$20,387,724	\$19,784,744	\$19,737,161	\$20,855,744	\$20,344,188	\$20,119,927	\$21,357,844	\$19,895,678	\$20,134,830	\$242,692,650
3														
4	Total Base Capacity Costs	\$18,965,613	\$19,242,486	\$20,658,686	\$19,980,564	\$19,450,179	\$19,462,879	\$20,066,748	\$19,833,535	\$19,693,349	\$20,267,568	\$19,041,033	\$19,663,641	\$236,326,282
5	Base Jurisdictional Factor ^(a)	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%
6	Total Base Jurisdictionalized Capacity Costs	\$18,148,024	\$18,412,962	\$19,768,110	\$19,119,222	\$18,611,701	\$18,623,853	\$19,201,691	\$18,978,531	\$18,844,388	\$19,393,854	\$18,220,193	\$18,815,961	\$226,138,492
7														
8	Total General Capacity Costs	\$1,090	(\$16)	(\$16)	(\$2,408)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,349)
9	General Jurisdictional Factor ^(a)	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%
10	Total General Jurisdictionalized Capacity Costs	\$1,058	(\$16)	(\$16)	(\$2,335)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,309)
11														
12	Total Intermediate Capacity Costs	\$352,944	\$377,529	\$334,440	\$359,141	\$281,387	\$233,934	\$759,627	\$461,300	\$377,279	\$1,033,298	\$750,450	\$435,663	\$5,756,991
13	Intermediate Jurisdictional Factor ^(a)	95.0081%	95.0081%	95.0081%	95.0081%	95.0081%	95.0081%	95.0081%	95.0081%	95.0081%	95.0081%	95.0081%	95.0081%	95.0081%
14	Total Intermediate Jurisdictionalized Capacity Costs	\$335,325	\$358,683	\$317,745	\$341,213	\$267,341	\$222,256	\$721,707	\$438,272	\$358,446	\$981,717	\$712,989	\$413,915	\$5,469,607
15														
16	Total Peaking Capacity Costs	\$31,808	\$29,268	\$31,387	\$37,923	\$38,225	\$33,366	\$23,475	\$43,486	\$43,456	\$46,170	\$33,455	\$33,527	\$425,545
17	Peaking Jurisdictional Factor ^(a)	95.2778%	95.2778%	95.2778%	95.2778%	95.2778%	95.2778%	95.2778%	95.2778%	95.2778%	95.2778%	95.2778%	95.2778%	95.2778%
18	Total Peaking Jurisdictionalized Capacity Costs	\$30,306	\$27,886	\$29,905	\$36,132	\$36,420	\$31,790	\$22,366	\$41,432	\$41,404	\$43,990	\$31,875	\$31,944	\$405,450
19														
20	Total Solar Capacity Costs	\$27,422	\$6,346	\$15,826	\$12,504	\$14,952	\$6,983	\$5,894	\$5,868	\$5,842	\$10,807	\$70,739	\$1,999	\$185,182
21	Solar Jurisdictional Factor ^(a)	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%	95.6891%
22	Total Solar Jurisdictionalized Capacity Costs	\$26,240	\$6,072	\$15,144	\$11,965	\$14,308	\$6,682	\$5,640	\$5,615	\$5,590	\$10,341	\$67,690	\$1,913	\$177,199
23														
24	Total Transmission Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Transmission Jurisdictional Factor ^(a)	90.2300%	90.2300%	90.2300%	90.2300%	90.2300%	90.2300%	90.2300%	90.2300%	90.2300%	90.2300%	90.2300%	90.2300%	90.2300%
26	Total Transmission Jurisdictionalized Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
27														
28	Jurisdictionalized Capacity Costs	\$18,540,953	\$18,805,587	\$20,130,888	\$19,506,196	\$18,929,770	\$18,884,581	\$19,951,404	\$19,463,851	\$19,249,829	\$20,429,902	\$19,032,747	\$19,263,733	\$232,189,440

^(a) As approved in Order No. PSC-2020-0439-FOF-EI

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Calculation of Actual/Estimated True-Up Amount

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Net Jurisdictional CCR Costs (Page 2, Line 28)	\$18,540,953	\$18,805,587	\$20,130,888	\$19,506,196	\$18,929,770	\$18,884,581	\$19,951,404	\$19,463,851	\$19,249,829	\$20,429,902	\$19,032,747	\$19,263,733	\$232,189,440
2														
3	CCR Revenues (Net of Revenue Taxes)	\$15,065,530	\$14,858,077	\$15,403,401	\$16,312,714	\$18,376,436	\$19,155,420	\$20,590,800	\$21,170,363	\$20,593,810	\$18,651,964	\$16,581,798	\$15,401,380	\$212,161,693
4	Prior Period True-Up Provision	\$1,044,202	\$1,044,202	\$1,044,202	\$1,044,202	\$1,044,202	\$1,044,202	\$1,044,202	\$1,044,202	\$1,044,202	\$1,044,202	\$1,044,202	\$1,044,202	\$12,530,421
5	SoBRA True-Up	\$1,033,490	\$1,033,490	\$1,033,490	\$1,033,490	\$1,033,490	\$1,033,490	\$1,033,490	\$1,033,490	\$1,033,490	\$1,033,490	\$1,033,490	\$1,033,490	\$12,401,882
6	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	\$17,143,222	\$16,935,768	\$17,481,093	\$18,390,406	\$20,454,128	\$21,233,112	\$22,668,492	\$23,248,055	\$22,671,502	\$20,729,656	\$18,659,490	\$17,479,072	\$237,093,996
7														
8	True-Up Provision - Over/(Under) Recovery (Line 6 - Line 1)	(\$1,397,730)	(\$1,869,818)	(\$2,649,795)	(\$1,115,790)	\$1,524,359	\$2,348,530	\$2,717,087	\$3,784,204	\$3,421,673	\$299,755	(\$373,257)	(\$1,784,661)	\$4,904,556
9	Interest Provision	\$1,916	\$1,653	\$1,584	\$1,129	\$604	\$652	\$831	\$840	\$942	\$928	\$787	\$576	\$12,441
10	True-Up & Interest Provision Beginning of Year - Over/(Under) Recovery	\$24,932,303	\$21,458,797	\$17,512,939	\$12,787,036	\$9,594,683	\$9,041,954	\$9,313,444	\$9,953,670	\$11,661,023	\$13,005,946	\$11,228,937	\$8,778,774	\$24,932,303
11	Deferred True-Up - Over/(Under) Recovery	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612	\$3,863,612
12	Prior Period True-Up Provision - Collected/(Refunded)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$1,044,202)	(\$12,530,421)
13	SoBRA True-Up	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$1,033,490)	(\$12,401,882)
14	End of Period True-Up - Over/(Under) Recovery (Lines 8 through 13)	\$25,322,409	\$21,376,552	\$16,650,649	\$13,458,296	\$12,905,566	\$13,177,057	\$13,817,283	\$15,524,635	\$16,869,559	\$15,092,549	\$12,642,387	\$8,780,610	\$8,780,610

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Calculation of Variances

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Program	Actual/Estimated True-Up	Projection	\$ Difference	% Difference
1					
2	Payments to Non-cogenerators	\$16,136,000	\$16,136,000	-	N/A
3	Payments to Co-generators	\$1,467,900	\$1,467,900	-	N/A
4	Transmission of Electricity by Others	\$162,610	(\$375,581)	\$538,191	(143.3%)
5	Transmission Revenues from Capacity Sales	(\$8,679,744)	(\$7,058,290)	(\$1,621,454)	23.0%
6	Incremental Plant Security Costs O&M	\$33,996,102	\$36,330,489	(\$2,334,387)	(6.4%)
7	Incremental Plant Security Costs Capital	\$5,403,909	\$5,877,775	(\$473,866)	(8.1%)
8	Incremental Nuclear NRC Compliance Costs O&M	\$1,072,001	\$1,280,315	(\$208,314)	(16.3%)
9	Incremental Nuclear NRC Compliance Costs Capital	\$12,707,875	\$13,138,414	(\$430,539)	(3.3%)
10	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	\$106,413,233	\$106,462,931	(\$49,698)	(0.0%)
11	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	(\$935,041)	(\$935,692)	\$651	(0.1%)
12	Indiantown Transaction - Regulatory Asset - Amortization and Return	\$68,235,997	\$68,293,477	(\$57,480)	(0.1%)
13	SJRPP Transaction Revenue Requirements	\$6,711,807	\$7,915,886	(\$1,204,079)	(15.2%)
14	Total	\$242,692,650	\$248,533,626	(\$5,840,976)	(2.4%)

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Calculation of Variances

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Line	Actual/Estimated True-Up	Projection	\$ Difference	% Difference
1	Total Capacity Costs	\$242,692,650	\$248,533,626	(\$5,840,976)	(2.4%)
2					
3	Total Base Capacity Costs	\$236,326,282	\$242,237,843	(\$5,911,561)	(2.4%)
4	Base Jurisdictional Factor	95.68910%	95.68908%		
5	Total Base Jurisdictionalized Capacity Costs	\$226,138,492	\$231,795,159	(\$5,656,667)	(2.4%)
6					
7	Total General Capacity Costs	(\$1,349)	\$81,328	(\$82,677)	(101.7%)
8	General Jurisdictional Factor	96.98880%	96.98877%		
9	Total General Jurisdictionalized Capacity Costs	(\$1,309)	\$78,879	(\$80,187)	(101.7%)
10					
11	Total Intermediate Capacity Costs	\$5,756,991	\$5,406,701	\$350,290	6.5%
12	Intermediate Jurisdictional Factor	95.00810%	95.00813%		
13	Total Intermediate Jurisdictionalized Capacity Costs	\$5,469,607	\$5,136,805	\$332,802	6.5%
14					
15	Total Peaking Capacity Costs	\$425,545	\$602,225	(\$176,680)	(29.3%)
16	Peaking Jurisdictional Factor	95.27780%	95.27777%		
17	Total Peaking Jurisdictionalized Capacity Costs	\$405,450	\$573,786	(\$168,337)	(29.3%)
18					
19	Total Solar Capacity Costs	\$185,182	\$205,530	(\$20,347)	(9.9%)
20	Solar Jurisdictional Factor	95.68910%	95.68908%		
21	Total Solar Jurisdictionalized Capacity Costs	\$177,199	\$196,670	(\$19,470)	(9.9%)
22					
23	Jurisdictional Capacity Charges	\$232,189,440	\$237,781,299	(\$5,591,859)	(2.4%)
24					
25	CCR Revenues (Net of Revenue Taxes)	\$212,161,693	212,848,995	(\$687,303)	(0.3%)
26	Prior Period True-up Provision	\$12,530,421	\$12,530,421	-	N/A
27	SoBRA True-Up	\$12,401,882	\$12,401,882	-	N/A
28	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	\$237,093,996	\$237,781,299	(\$687,303)	(0.3%)
29					
30	True-up Provision for Month - Over/(Under) Recovery	\$4,904,556	-	\$4,904,556	N/A
31	Interest Provision for the Month	\$12,441	-	\$12,441	N/A
32	True-up & Interest Provision Beginning of Year - Over/(Under) Recovery	\$24,932,303	\$24,932,303	-	N/A
33	Deferred True-up - Over/(Under) Recovery	\$3,863,612	-	\$3,863,612	N/A
34	Prior Period True-up Provision - Collected/(Refunded) this Month	(\$12,530,421)	(\$12,530,421)	-	N/A
35	SoBRA True-Up	(\$12,401,882)	(\$12,401,882)	-	N/A
36	End of Period True-up - Over/(Under) Recovery	\$8,780,610	-	\$8,780,610	N/A
37					

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
202-INCREMENTAL SECURITY														
Base														
1. Investments														
a. Expenditures/Additions		\$994	\$235,634	\$351	-	\$15,051	\$3,329	\$160,576	-	\$785,166	-	-	-	\$1,201,100
b. Additions to Plants		(\$174,489)	(\$216,144)	(\$1,371)	-	-	(\$65,785)	-	-	-	\$1,885,519	-	-	\$1,427,730
c. Retirements		(\$188,117)	-	-	-	-	-	-	-	-	-	(\$1,250,338)	(\$1,145,413)	(\$2,583,868)
d. Cost of Removal		\$1,638	\$760	(\$1,371)	-	(\$205)	(\$263)	-	-	-	-	-	-	\$559
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$38,907,595	\$38,733,106	\$38,516,962	\$38,515,591	\$38,515,591	\$38,515,591	\$38,449,806	\$38,449,806	\$38,449,806	\$38,449,806	\$40,335,325	\$40,335,325	\$40,335,325	
3. Less: Accumulated Depreciation	\$3,857,247	\$3,800,938	\$3,931,676	\$4,060,080	\$4,189,854	\$4,319,423	\$4,448,847	\$4,578,449	\$4,708,051	\$4,837,654	\$4,967,256	\$3,846,519	\$2,830,709	
4. CWIP - Non Interest Bearing	\$1,994,471	\$1,995,465	\$2,231,099	\$2,231,449	\$2,231,449	\$2,246,501	\$2,249,830	\$2,410,406	\$2,410,406	\$3,195,572	\$1,310,053	\$1,310,053	\$1,310,053	
5. Net Investment (Lines 2 - 3 + 4)	\$37,044,819	\$36,927,633	\$36,816,384	\$36,686,960	\$36,557,186	\$36,442,669	\$36,250,788	\$36,281,762	\$36,152,160	\$36,807,724	\$36,678,122	\$37,798,858	\$38,814,669	
6. Average Net Investment		\$36,986,226	\$36,872,009	\$36,751,672	\$36,622,073	\$36,499,928	\$36,346,728	\$36,266,275	\$36,216,961	\$36,479,942	\$36,742,923	\$37,238,490	\$38,306,763	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ^(a)		\$209,550	\$208,902	\$208,221	\$207,486	\$206,794	\$205,926	\$205,471	\$205,191	\$206,681	\$208,171	\$210,979	\$217,031	\$2,500,404
b. Debt Component (Line 6 x debt rate) ^(b)		\$37,153	\$37,038	\$36,917	\$36,787	\$36,664	\$36,510	\$36,429	\$36,380	\$36,644	\$36,908	\$37,406	\$38,479	\$443,316
8. Investment Expenses														
a. Depreciation		\$130,169	\$129,979	\$129,775	\$129,774	\$129,774	\$129,688	\$129,602	\$129,602	\$129,602	\$129,602	\$129,602	\$129,602	\$1,556,770
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$376,871	\$375,919	\$374,913	\$374,047	\$373,232	\$372,125	\$371,502	\$371,173	\$372,927	\$374,681	\$377,987	\$385,112	\$4,500,490

^(a) The Gross-up factor for taxes is 1/754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
202-INCREMENTAL SECURITY														
General														
1. Investments														
a. Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
b. Additions to Plants		(\$132,325)	-	-	-	-	-	-	-	-	-	-	-	(\$132,325)
c. Retirements		(\$132,325)	-	-	-	-	-	-	-	-	-	-	-	(\$132,325)
d. Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$132,325	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
3. Less: Accumulated Depreciation	\$133,621	\$2,400	\$2,400	\$2,400	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
4. CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
5. Net Investment (Lines 2 - 3 + 4)	(\$1,297)	(\$2,399)	(\$2,399)	(\$2,399)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
6. Average Net Investment		(\$1,848)	(\$2,399)	(\$2,399)	(\$1,200)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ^(a)		(\$10)	(\$14)	(\$14)	(\$7)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$44)
b. Debt Component (Line 6 x debt rate) ^(b)		(\$2)	(\$2)	(\$2)	(\$1)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$8)
8. Investment Expenses														
a. Depreciation		\$1,103	-	-	(\$2,400)	-	-	-	-	-	-	-	-	(\$1,297)
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$1,090	(\$16)	(\$16)	(\$2,408)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,349)

^(a) The Gross-up factor for taxes is 1/.754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
202-INCREMENTAL SECURITY														
Intermediate														
1. Investments														
a. Expenditures/Additions		-	(\$17,515)	\$475,232	(\$722,453)	-	-	-	\$87,470	\$87,470	\$80,026	-	-	(\$9,771)
b. Additions to Plants		(\$562)	\$137,753	\$0	\$1,271,612	(\$36,320)	\$100,880	-	-	-	\$254,966	-	-	\$1,728,329
c. Retirements		-	-	-	-	(\$36,841)	-	-	-	-	-	-	-	(\$36,841)
d. Cost of Removal		(\$9,577)	(\$13,773)	(\$52,839)	(\$61,059)	(\$58)	(\$11,216)	-	-	-	-	-	-	(\$148,523)
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$6,064,224	\$6,063,662	\$6,201,415	\$6,201,415	\$7,473,027	\$7,436,707	\$7,537,587	\$7,537,587	\$7,537,587	\$7,537,587	\$7,792,553	\$7,792,553	\$7,792,553	
3. Less: Accumulated Depreciation	\$889,772	\$897,242	\$900,694	\$865,258	\$823,186	\$806,819	\$816,221	\$836,965	\$857,709	\$878,453	\$899,446	\$920,687	\$941,928	
4. CWIP - Non Interest Bearing	\$301,371	\$301,371	\$283,855	\$759,087	\$36,634	\$36,634	\$36,634	\$36,634	\$124,104	\$211,574	\$36,634	\$36,634	\$36,634	
5. Net Investment (Lines 2 - 3 + 4)	\$5,475,822	\$5,467,791	\$5,584,576	\$6,095,245	\$6,686,476	\$6,666,522	\$6,758,000	\$6,737,255	\$6,803,981	\$6,870,707	\$6,929,741	\$6,908,500	\$6,887,258	
6. Average Net Investment		\$5,471,806	\$5,526,184	\$5,839,911	\$6,390,860	\$6,676,499	\$6,712,261	\$6,747,627	\$6,770,618	\$6,837,344	\$6,900,224	\$6,919,120	\$6,897,879	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ^(a)		\$31,001	\$31,309	\$33,087	\$36,208	\$37,826	\$38,029	\$38,229	\$38,360	\$38,738	\$39,094	\$39,201	\$39,081	\$440,163
b. Debt Component (Line 6 x debt rate) ^(b)		\$5,496	\$5,551	\$5,866	\$6,420	\$6,707	\$6,742	\$6,778	\$6,801	\$6,868	\$6,931	\$6,950	\$6,929	\$78,040
8. Investment Expenses														
a. Depreciation		\$17,047	\$17,225	\$17,403	\$18,987	\$20,532	\$20,618	\$20,744	\$20,744	\$20,744	\$20,993	\$21,241	\$21,241	\$237,519
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$53,544	\$54,085	\$56,356	\$61,615	\$65,065	\$65,390	\$65,751	\$65,905	\$66,350	\$67,018	\$67,393	\$67,251	\$755,723

^(a) The Gross-up factor for taxes is 1/.754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
202-INCREMENTAL SECURITY														
Peaking														
1. Investments														
a. Expenditures/Additions		-	(\$73,850)	-	-	-	-	-	-	-	-	-	-	(\$73,850)
b. Additions to Plants		-	\$77,486	\$0	-	-	-	-	-	-	-	-	-	\$77,486
c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Cost of Removal		-	-	\$0	-	-	-	-	-	-	-	-	-	\$0
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$672,783	\$672,783	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	
3. Less: Accumulated Depreciation	\$181,191	\$184,106	\$187,121	\$190,237	\$193,353	\$196,469	\$199,585	\$202,701	\$205,817	\$208,932	\$212,048	\$215,164	\$218,280	
4. CWIP - Non Interest Bearing	\$37,154	\$37,154	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	
5. Net Investment (Lines 2 - 3 + 4)	\$528,746	\$525,831	\$526,451	\$523,335	\$520,220	\$517,104	\$513,988	\$510,872	\$507,756	\$504,640	\$501,525	\$498,409	\$495,293	
6. Average Net Investment		\$527,289	\$526,141	\$524,893	\$521,777	\$518,662	\$515,546	\$512,430	\$509,314	\$506,198	\$503,082	\$499,967	\$496,851	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ^(a)		\$2,987	\$2,981	\$2,974	\$2,956	\$2,939	\$2,921	\$2,903	\$2,886	\$2,868	\$2,850	\$2,833	\$2,815	\$34,912
b. Debt Component (Line 6 x debt rate) ^(b)		\$530	\$529	\$527	\$524	\$521	\$518	\$515	\$512	\$508	\$505	\$502	\$499	\$6,190
8. Investment Expenses														
a. Depreciation		\$2,915	\$3,015	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$37,089
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$6,432	\$6,525	\$6,617	\$6,596	\$6,575	\$6,555	\$6,534	\$6,513	\$6,492	\$6,471	\$6,451	\$6,430	\$78,191

^(a) The Gross-up factor for taxes is 1/.754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
203-INCREMENTAL SECURITY - SOLAR														
Solar														
1. Investments														
a. Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
b. Additions to Plants		-	\$1,819	-	-	-	-	-	-	-	-	-	-	\$1,819
c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$327,705	\$327,705	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524
3. Less: Accumulated Depreciation	\$8,491	\$12,392	\$16,304	\$20,240	\$24,166	\$28,089	\$32,012	\$35,935	\$39,858	\$43,781	\$47,704	\$51,627	\$55,550	
4. CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
5. Net Investment (Lines 2 - 3 + 4)	\$319,215	\$315,314	\$313,220	\$309,284	\$305,358	\$301,435	\$297,512	\$293,589	\$289,666	\$285,743	\$281,820	\$277,897	\$273,974	
6. Average Net Investment		\$317,264	\$314,267	\$311,252	\$307,321	\$303,397	\$299,474	\$295,551	\$291,628	\$287,705	\$283,782	\$279,859	\$275,936	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ^(a)		\$1,797	\$1,781	\$1,763	\$1,741	\$1,719	\$1,697	\$1,674	\$1,652	\$1,630	\$1,608	\$1,586	\$1,563	\$20,212
b. Debt Component (Line 6 x debt rate) ^(b)		\$319	\$316	\$313	\$309	\$305	\$301	\$297	\$293	\$289	\$285	\$281	\$277	\$3,583
8. Investment Expenses														
a. Depreciation		\$3,901	\$3,912	\$3,936	\$3,926	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$47,059
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$6,017	\$6,008	\$6,012	\$5,976	\$5,947	\$5,921	\$5,894	\$5,868	\$5,842	\$5,816	\$5,790	\$5,763	\$70,854

^(a) The Gross-up factor for taxes is 1/.754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Return on Capital Investments, Depreciation and Taxes

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
201-FUKUSHIMA														
Base														
1. Investments														
a. Expenditures/Additions		-	-	-	\$600,567	-	\$41,585	-	-	-	-	-	-	\$642,153
b. Additions to Plants		\$122,917	\$214,792	\$390,346	\$2,781,355	\$29,291	\$67,805	-	-	-	-	-	-	\$3,606,505
c. Retirements		-	-	-	(\$104,960)	-	-	-	-	-	-	-	-	(\$104,960)
d. Cost of Removal		(\$9,949)	(\$22,806)	(\$19,772)	(\$3,640)	(\$3,796)	(\$2,143)	-	-	-	-	-	-	(\$62,107)
e. Salvage		-	-	-	\$2,744,120	-	-	-	-	-	-	-	-	\$2,744,120
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$107,198,477	\$107,321,393	\$107,536,186	\$107,926,531	\$110,707,886	\$110,737,177	\$110,804,982	\$110,804,982	\$110,804,982	\$110,804,982	\$110,804,982	\$110,804,982	\$110,804,982	
3. Less: Accumulated Depreciation	\$11,321,880	\$11,721,905	\$12,109,725	\$12,501,732	\$15,555,612	\$15,976,072	\$16,398,386	\$16,822,989	\$17,247,592	\$17,672,195	\$18,099,862	\$18,523,150	\$18,932,178	
4. CWIP - Non Interest Bearing	\$1,243,367	\$1,243,367	\$1,243,367	\$1,243,367	\$1,843,934	\$1,843,934	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	
5. Net Investment (Lines 2 - 3 + 4)	\$97,119,964	\$96,842,855	\$96,669,827	\$96,668,166	\$96,996,208	\$96,605,039	\$96,292,115	\$95,867,512	\$95,442,910	\$95,018,307	\$94,590,640	\$94,167,352	\$93,758,324	
6. Average Net Investment		\$96,981,410	\$96,756,341	\$96,668,997	\$96,832,187	\$96,800,624	\$96,448,577	\$96,079,814	\$95,655,211	\$95,230,608	\$94,804,473	\$94,378,996	\$93,962,838	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ^(a)		\$549,459	\$548,184	\$547,689	\$548,613	\$548,435	\$546,440	\$544,351	\$541,945	\$539,540	\$537,125	\$534,715	\$532,357	\$6,518,852
b. Debt Component (Line 6 x debt rate) ^(b)		\$97,418	\$97,192	\$97,104	\$97,268	\$97,236	\$96,883	\$96,512	\$96,086	\$95,659	\$95,231	\$94,804	\$94,386	\$1,155,778
8. Investment Expenses														
a. Depreciation		\$409,974	\$410,626	\$411,779	\$418,360	\$424,257	\$424,458	\$424,603	\$424,603	\$424,603	\$427,667	\$423,288	\$409,028	\$5,033,245
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7		\$1,056,851	\$1,056,002	\$1,056,572	\$1,064,242	\$1,069,928	\$1,067,780	\$1,065,466	\$1,062,634	\$1,059,802	\$1,060,023	\$1,052,807	\$1,035,770	\$12,707,875

^(a) The Gross-up factor for taxes is 1/.754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Cedar Bay Transaction - Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Regulatory Asset Loss of PPA ^(c)		\$223,071,453	\$218,424,131	\$213,776,809	\$209,129,487	\$204,482,165	\$199,834,843	\$195,187,521	\$190,540,199	\$185,892,877	\$181,245,555	\$176,598,233	\$171,950,911	
2															
3	Regulatory Asset - Loss of PPA Amort		\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$55,767,864
4															
5	Unamortized Regulatory Asset - Loss of PPA	\$223,071,453	\$218,424,131	\$213,776,809	\$209,129,487	\$204,482,165	\$199,834,843	\$195,187,521	\$190,540,199	\$185,892,877	\$181,245,555	\$176,598,233	\$171,950,911	\$167,303,589	
6															
7	Average Unamortized Regulatory Asset - Loss of PPA		\$220,747,792	\$216,100,470	\$211,453,148	\$206,805,826	\$202,158,504	\$197,511,182	\$192,863,860	\$188,216,538	\$183,569,216	\$178,921,894	\$174,274,572	\$169,627,250	
8															
9	Regulatory Asset - Income Tax Gross Up		\$140,089,201	\$137,170,676	\$134,252,151	\$131,333,626	\$128,415,101	\$125,496,576	\$122,578,051	\$119,659,526	\$116,741,001	\$113,822,476	\$110,903,951	\$107,985,426	
10															
11	Regulatory Asset Amortization - Income Tax Gross-Up		\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$35,022,300
12															
13	Unamortized Regulatory Asset - Income Tax Gross Up	\$140,089,201	\$137,170,676	\$134,252,151	\$131,333,626	\$128,415,101	\$125,496,576	\$122,578,051	\$119,659,526	\$116,741,001	\$113,822,476	\$110,903,951	\$107,985,426	\$105,066,901	
14															
15	Return on Unamortized Regulatory Asset - Loss of PPA only														
16	Equity Component		\$943,984	\$924,110	\$904,237	\$884,364	\$864,490	\$844,617	\$824,744	\$804,870	\$784,997	\$765,124	\$745,250	\$725,377	\$10,016,165
17															
18	Equity Comp. grossed up for taxes ^(a)		\$1,250,671	\$1,224,341	\$1,198,011	\$1,171,681	\$1,145,351	\$1,119,022	\$1,092,692	\$1,066,362	\$1,040,032	\$1,013,702	\$987,372	\$961,042	\$13,270,279
19															
20	Debt Component (Line 4 * debt rate / 12) ^(a)		\$221,741	\$217,073	\$212,405	\$207,736	\$203,068	\$198,400	\$193,732	\$189,064	\$184,395	\$179,727	\$175,059	\$170,391	\$2,352,790
21															
22	Total Return Requirements (Line 18 + 20)		\$1,472,412	\$1,441,414	\$1,410,416	\$1,379,418	\$1,348,420	\$1,317,421	\$1,286,423	\$1,255,425	\$1,224,427	\$1,193,429	\$1,162,431	\$1,131,433	\$15,623,069
23	Total Recoverable Costs (Line 3 + 11 + 22)		\$9,038,259	\$9,007,261	\$8,976,263	\$8,945,265	\$8,914,267	\$8,883,268	\$8,852,270	\$8,821,272	\$8,790,274	\$8,759,276	\$8,728,278	\$8,697,280	\$106,413,233
24															
25															

^(a) The Gross-up factor for taxes is 1/.754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

^(c) Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI, Order No. PSC-15-0401-AS-EI.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Cedar Bay Transaction - Regulatory Liability - Book/Tax Timing Difference Associated to Plant Asset

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Regulatory Liability - Book/Tax Timing Difference ^(c)		(\$2,921,701)	(\$2,860,833)	(\$2,799,965)	(\$2,739,097)	(\$2,678,229)	(\$2,617,361)	(\$2,556,493)	(\$2,495,625)	(\$2,434,757)	(\$2,373,889)	(\$2,313,021)	(\$2,252,153)	
2															
3	Regulatory Liability Amortization		\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$730,416
4															
5	Unamortized Regulatory Liability - Book/Tax Timing Diff	(\$2,921,701)	(\$2,860,833)	(\$2,799,965)	(\$2,739,097)	(\$2,678,229)	(\$2,617,361)	(\$2,556,493)	(\$2,495,625)	(\$2,434,757)	(\$2,373,889)	(\$2,313,021)	(\$2,252,153)	(\$2,191,285)	
6															
7	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		(\$2,891,267)	(\$2,830,399)	(\$2,769,531)	(\$2,708,663)	(\$2,647,795)	(\$2,586,927)	(\$2,526,059)	(\$2,465,191)	(\$2,404,323)	(\$2,343,455)	(\$2,282,587)	(\$2,221,719)	
8															
9	Return on Unamortized Regulatory Asset - Loss of PPA only														
10	Equity Component		(\$12,364)	(\$12,104)	(\$11,843)	(\$11,583)	(\$11,323)	(\$11,062)	(\$10,802)	(\$10,542)	(\$10,282)	(\$10,021)	(\$9,761)	(\$9,501)	(\$131,188)
11															
12	Equity Comp. grossed up for taxes ^(a)		(\$16,381)	(\$16,036)	(\$15,691)	(\$15,346)	(\$15,001)	(\$14,657)	(\$14,312)	(\$13,967)	(\$13,622)	(\$13,277)	(\$12,932)	(\$12,587)	(\$173,809)
13															
14	Debt Component (Line 8 * debt rate / 12) ^(b)		(\$2,904)	(\$2,843)	(\$2,782)	(\$2,721)	(\$2,660)	(\$2,599)	(\$2,537)	(\$2,476)	(\$2,415)	(\$2,354)	(\$2,293)	(\$2,232)	(\$30,816)
15															
16	Total Return Requirements (Line 12 + 14)		(\$19,285)	(\$18,879)	(\$18,473)	(\$18,067)	(\$17,661)	(\$17,255)	(\$16,849)	(\$16,443)	(\$16,037)	(\$15,631)	(\$15,225)	(\$14,819)	(\$204,625)
17	Total Recoverable Costs (Line 3 + 16)		(\$80,153)	(\$79,747)	(\$79,341)	(\$78,935)	(\$78,529)	(\$78,123)	(\$77,717)	(\$77,311)	(\$76,905)	(\$76,499)	(\$76,093)	(\$75,687)	(\$935,041)

^(a) The Gross-up factor for taxes is 1/.754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

^(c) Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI, Order No. PSC-15-0401-AS-EI.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
Indiantown Transaction - Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Regulatory Asset Loss of PPA ^(a)		\$250,833,333	\$246,652,777	\$242,472,221	\$238,291,666	\$234,111,110	\$229,930,555	\$225,749,999	\$221,569,444	\$217,388,888	\$213,208,333	\$209,027,777	\$204,847,221	
2															
3	Regulatory Asset - Loss of PPA Amort		\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$50,166,667
4															
5	Unamortized Regulatory Asset - Loss of PPA	\$250,833,333	\$246,652,777	\$242,472,221	\$238,291,666	\$234,111,110	\$229,930,555	\$225,749,999	\$221,569,444	\$217,388,888	\$213,208,333	\$209,027,777	\$204,847,221	\$200,666,666	
6															
7	Average Unamortized Regulatory Asset - Loss of PPA		\$248,743,055	\$244,562,499	\$240,381,944	\$236,201,388	\$232,020,833	\$227,840,277	\$223,659,721	\$219,479,166	\$215,298,610	\$211,118,055	\$206,937,499	\$202,756,944	
8															
9	Return on Unamortized Regulatory Asset - Loss of PPA only														
10	Equity Component		\$1,063,700	\$1,045,823	\$1,027,945	\$1,010,068	\$992,191	\$974,313	\$956,436	\$938,559	\$920,681	\$902,804	\$884,927	\$867,050	\$11,584,497
11															
12	Equity Comp. grossed up for taxes ^(a)		\$1,409,281	\$1,385,596	\$1,361,911	\$1,338,225	\$1,314,540	\$1,290,854	\$1,267,169	\$1,243,484	\$1,219,798	\$1,196,113	\$1,172,427	\$1,148,742	\$15,348,140
13															
14	Debt Component (Line 4 * debt rate / 12) ^(b)		\$249,862	\$245,663	\$241,464	\$237,264	\$233,065	\$228,866	\$224,666	\$220,467	\$216,267	\$212,068	\$207,869	\$203,669	\$2,721,190
15															
16	Total Return Requirements (Line 13 + 15)		\$1,659,144	\$1,631,259	\$1,603,374	\$1,575,489	\$1,547,605	\$1,519,720	\$1,491,835	\$1,463,950	\$1,436,066	\$1,408,181	\$1,380,296	\$1,352,411	\$18,069,330
17	Total Recoverable Costs (Line 4 + 17)		\$5,839,699	\$5,811,815	\$5,783,930	\$5,756,045	\$5,728,160	\$5,700,275	\$5,672,391	\$5,644,506	\$5,616,621	\$5,588,736	\$5,560,852	\$5,532,967	\$68,235,997

^(a) The Gross-up factor for taxes is 1/754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

^(c) Recovery of the Indiantown Transaction is based on the settlement agreement approved by the FPSC in Docket No. 160154-EI, Order No. PSC-16-0506-FOF-EI.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Actual/Estimated True-Up
SJRP Transaction - Regulatory Assets and Liabilities Related to the SJRP Transaction

FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Line	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Regulatory Asset - SJRP Transaction Shutdown Payment ^(c)		\$19,652,174	\$17,686,957	\$15,721,739	\$13,756,522	\$11,791,305	\$9,826,087	\$7,860,870	\$5,895,653	\$3,930,435	\$1,965,218	-	-	\$108,086,961
2	Regulatory Asset - SJRP Transaction Shutdown Payment Amortization		\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,217	\$1,965,218	-	-	\$19,652,174
3	Unamortized Regulatory Asset - SJRP Transaction Shutdown Payment	\$19,652,174	\$17,686,957	\$15,721,739	\$13,756,522	\$11,791,305	\$9,826,087	\$7,860,870	\$5,895,653	\$3,930,435	\$1,965,218	-	-	-	
4															
5	Other regulatory liability - SJRP Suspension Liability		(\$2,153,173)	(\$1,937,856)	(\$1,722,538)	(\$1,507,221)	(\$1,291,904)	(\$1,076,587)	(\$861,269)	(\$645,952)	(\$430,635)	(\$215,318)	-	-	
6	Other regulatory liability - SJRP Suspension Liability Amortization (Refund)		(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,317)	(\$215,318)	-	-	(\$2,153,173)
7	Unamortized Regulatory Liability - SJRP Suspension Liability	(\$2,153,173)	(\$1,937,856)	(\$1,722,538)	(\$1,507,221)	(\$1,291,904)	(\$1,076,587)	(\$861,269)	(\$645,952)	(\$430,635)	(\$215,318)	-	-	-	
8															
9	Average Net Unamortized Regulatory Asset/Liab (Lines 3 + 7)		\$16,624,051	\$14,874,151	\$13,124,251	\$11,374,351	\$9,624,451	\$7,874,551	\$6,124,651	\$4,374,751	\$2,624,850	\$874,950	-	-	\$87,495,008
10															
11	Equity Component		\$71,089	\$63,606	\$56,123	\$48,640	\$41,157	\$33,674	\$26,191	\$18,708	\$11,225	\$3,742	-	-	\$374,155
12	Equity Comp. grossed up for taxes		\$94,185	\$84,271	\$74,357	\$64,443	\$54,528	\$44,614	\$34,700	\$24,786	\$14,871	\$4,957	-	-	\$495,713
13	Debt Component (Line 9 x debt rate x 1/12) ^(a)		\$16,699	\$14,941	\$13,183	\$11,426	\$9,668	\$7,910	\$6,152	\$4,394	\$2,637	\$879	-	-	\$87,889
14															
15	Total Return Requirements (Line 12 + 13) ^(b)		\$110,884	\$99,212	\$87,540	\$75,868	\$64,196	\$52,524	\$40,852	\$29,180	\$17,508	\$5,836	-	-	\$583,601
16															
17	Other SJRP Transaction Items ^(d)														
18	SJRP Deferred Interest Amortization (Refund)		(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	(\$269,182)	-	-	(\$2,691,818)
19	SJRP Article 8 PPA Dismantlement Accrual Amortization (Refund)		(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	(\$867,898)	-	-	(\$8,678,978)
20															
21	Total Recoverable Expenses (Lines 2 + 6 + 12 + 13 + 18 + 19)		\$723,705	\$712,033	\$700,361	\$688,689	\$677,017	\$665,345	\$653,673	\$642,001	\$630,329	\$618,657	-	-	\$6,711,807
22															

^(a) The Gross-up factor for taxes is 1/754782, which reflects the Federal Income Tax Rate of 21%. The equity component for the period Jan. – Dec. 2021 is 5.1316% based on FPL's most recent financial forecast.

^(b) The debt component is 1.2054% based on FPL's most recent financial forecast.

^(c) Recovery of the SJRP Transaction over a 46 month period is based on the settlement agreement approved by the FPSC in Docket No. 20170123-EI Order No. PSC-2017-0415-AS-EI.

^(d) The total amount of SJRP Deferred Interest and Article 8 PPA Dismantlement Accrual to refund is \$12.4M and \$39.9M, respectively. The unamortized balances for these regulatory liabilities are a reflected in rate base.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES
ACT/EST 2021 WACC @10.55%

CAPITAL STRUCTURE AND COST RATES (a)

	Adjusted Retail	Ratio	Midpoint Cost Rates	Weighted Cost	Pre-Tax Weighted Cost
Long term debt	\$14,562,650,096	30.989%	3.73%	1.1552%	1.16%
Short term debt	\$614,526,761	1.308%	0.75%	0.0098%	0.01%
Preferred stock	\$0	0.000%	0.00%	0.0000%	0.00%
Customer Deposits	\$386,833,886	0.823%	2.04%	0.0168%	0.02%
Common Equity ^(b)	\$22,399,858,657	47.667%	10.55%	5.0288%	6.66%
Deferred Income Tax	\$8,273,619,122	17.606%	0.00%	0.0000%	0.00%
Investment Tax Credits					
Zero cost	\$0	0.000%	0.00%	0.0000%	0.00%
Weighted cost	\$755,222,884	1.607%	7.86%	0.1264%	0.16%
TOTAL	\$46,992,711,405	100.00%		6.34%	8.00%

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

	Adjusted Retail	Ratio	Cost Rate	Weighted Cost	Pre-Tax Cost
Long term debt	\$14,562,650,096	39.40%	3.728%	1.469%	1.469%
Preferred Stock	\$0	0.00%	0.000%	0.000%	0.000%
Common Equity	\$22,399,858,657	60.60%	10.550%	6.393%	8.471%
TOTAL	\$36,962,508,752	100.00%		7.862%	9.939%

RATIO

DEBT COMPONENTS

Long term debt	1.1552%
Short term debt	0.0098%
Customer Deposits	0.0168%
Tax credits weighted	0.0236%
TOTAL DEBT	1.2054%

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	5.0288%
TAX CREDITS -WEIGHTED	0.1027%
TOTAL EQUITY	5.1316%
TOTAL	6.3370%
PRE-TAX EQUITY	6.7988%
PRE-TAX TOTAL	8.0042%

Note:

- (a) Forecasted capital structure includes a deferred income tax proration adjustment consistent with FPSC Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-
(b) Cost rate for common equity represents FPL's mid-point return on equity approved by the FPSC in Order No. PSC-16-0560-AS-EI, Docket Nos. 160021-EI, 160061-EI, 160062-EI, and
(c) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

**APPENDIX II
FUEL COST RECOVERY
2022 E-SCHEDULES**

FOR THE PERIOD JANUARY 2022 THROUGH DECEMBER 2022

**RBD-5
DOCKET NO. 20210001-EI
FPL WITNESS: RENAE B. DEATON
EXHIBIT _____
PAGES 1-143
SEPTEMBER 3, 2021**

**APPENDIX II
FUEL COST RECOVERY
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FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
FUEL AND PURCHASED POWER COSTS RECOVERY FACTOR

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)
Line No.		2022		
		Dollars	MWh	Cents/kWh
1	Total Cost Of Generated Power			
2	Fuel Cost of System Net Generation (per A3)	3,442,984,508	133,484,562	2.5793
3	Fuel Cost of Stratified Sales	(54,128,274)	(1,836,507)	2.9473
4	Rail Car Lease (Cedar Bay/Indiantown/Daniel)	2,059,102	N/A	
5	Adjustments to Fuel Costs (Per A2)	547,119	N/A	
6		3,391,462,454	131,648,055	2.5762
7	Total Cost Of Purchased Power			
8	Fuel Cost of Purchased Power (Exclusive of Economy) (Per A7)	213,898,442	6,930,893	3.0862
9	Energy Payments to Qualifying Facilities (Per A8)	24,793,908	685,635	3.6162
10	Energy Cost of Economy Purchases (Per A9)	14,336,279	539,355	2.6580
11		253,028,629	8,155,884	3.1024
12	TOTAL AVAILABLE (LINE 5+9)		139,803,939	
13	Total Fuel Cost And Gains Of Power Sales			
14	Fuel Cost of Economy and Other Power Sales (A6)	(132,227,866)	(5,287,720)	2.5007
15	Gains from Off-System Sales (Per A6)	(22,704,934)	N/A	
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (A6)	(2,996,664)	(578,523)	0.5180
17		(157,929,464)	(5,866,243)	2.6922
18	Total Incremental Optimization Costs			
19	Incremental Personnel, Software, and Hardware Costs	444,343	N/A	
20	Var. Power Plant O&M Costs Attributable to Off-Systems Sales (Per A6)	1,168,545	N/A	
21	Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	(224,432)	N/A	
22		1,388,456		
23	Total Fuel Costs & Net Power Transactions	3,487,950,075	133,937,696	2.6042
24	Average Factor Calculation			
25	Net Unbilled Sales ⁽¹⁾	17,046,901	654,603	0.0134
26	T & D Losses ⁽¹⁾	149,981,853	5,759,321	0.1177
27	Company Use ⁽¹⁾	3,487,950	133,938	0.0027
28	System MWH Sales (Excluding Stratified Sales)	3,487,950,075	127,389,834	2.7380
29	Wholesale MWH Sales (Excluding Stratified Sales)	144,931,302	5,293,333	2.7380
30	Jurisdictional MWH Sales	3,343,018,774	122,096,501	2.7380
31	Jurisdictional Loss Multiplier	5,582,841		1.00167
32	Jurisdictional KWH Sales Adjusted for Line Losses	3,348,601,615	122,096,501	2.7426
33	NET TRUE-UP (OVER)/UNDER RECOVERY ⁽²⁾	353,945,632	122,096,501	0.2899
34	TOTAL JURISDICTIONAL FUEL COST	3,702,547,248	122,096,501	3.0325
35	Revenue Tax Factor			1.00000
36	Fuel Factor Adjusted for Taxes	3,702,547,248	122,096,501	3.0325
37	GPIF ⁽³⁾	4,748,196	122,096,501	0.0039
38	Asset Optimization - FPL Portion ⁽⁴⁾	3,503,210	122,096,501	0.0029
39	SolarTogether (ST) Credit	113,512,426	122,096,501	0.0930
40	Fuel Factor Adjusted for GPIF	3,824,311,080	122,096,501	3.1323
41	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.132

⁽¹⁾ For informational purposes only

⁽²⁾ Includes 2020 Final True-up for Gulf and revised 2021 Actual/Estimated True-Up amounts for FPL and Gulf

⁽³⁾ Based on 2020 GPIF results for FPL and Gulf

⁽⁴⁾ Calculation based on Jurisdictional kWh sales

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF TOTAL TRUE-UP

SCHEDULE: E1-A

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)
Line No.		2022
1	Actual/Estimated over/(under) recovery ⁽¹⁾	(\$360,031,312)
2	Final over/(under) recovery ⁽²⁾	\$6,085,680
3	Total over/(under) recovery to be included in projected period ⁽³⁾	(\$353,945,632)
4		
5	Total Jurisdictional Sales (MWh)	122,096,501
6		
7	True-Up Factor (cents/kWh)	(0.2899)
8		
9		
10	⁽¹⁾ Revised 2021 Actual/Estimated True-Up amounts for FPL and Gulf	
11	⁽²⁾ Final True-up over/(under) recovery for January 2020 - December 2020, Gulf only	
12	⁽³⁾ Projected Period January 2022 - December 2022 (Schedule E1, Line 33)	
13		
14	Note: Totals may not add due to rounding.	

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ADJUSTMENT FACTORS

SCHEDULE: E1-C

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

	2022
1. Total Adjustments	
A. Generating Performance Incentive - Reward/(Penalty)	\$4,748,196
B. True-Up (Over)/Under Recovered	\$353,945,632
C. Asset Optimization - Company Portion	\$3,503,210
D. SolarTogether Credit	\$113,512,426
	<u>\$475,709,464</u>
2. Total Jurisdictional Sales (MWh)	122,096,501
3. Adjustment Factors (Cents/kWh)	
A. Generating Performance Incentive Factor	0.0039
B. True-Up Factor	0.2899
C. Asset Optimization - Company Portion	0.0029
D. SolarTogether Credit	0.0930
	<u>0.3896</u>

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)
Line No.	Asset Optimization Calculation	2022
1	Asset Optimization Gains ⁽¹⁾	\$3,681,030
2		
3	Actuals Year	<u>2020</u>
4	Actual Retail kWh sales	113,530,952,319
5	Actual Total System kWh sales	119,293,702,380
6	Actual Average Jurisdictional % ⁽²⁾	95.16928%
7		
8	Jurisdictionalized Asset Optimization Gains	\$3,503,210
9		
10	Revenue Tax Factor	1.00000
11		
12	Asset Optimization Gains, Adjusted for Revenue Taxes	\$3,503,210
13		
14	Projected Year	<u>2022</u>
15	Projected kWh Sales	122,096,501
16		
17	Asset Optimization Factor (cents/kWh)	0.0029
18		
19		
20	⁽¹⁾ Reflected on Exhibit GJY-1, filed on April 2, 2021	
21	⁽²⁾ Reflected on Schedule E1-B, filed on April 2, 2021	

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
DEVELOPMENT OF SEASONALLY DIFFERENTIATED TIME OF USE MULTIPLIERS

SCHEDULE: E1-D

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.		Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1	On Peak Period													
2	System MWH Requirements	2,539,823	2,505,110	2,755,518	3,497,856	3,836,838	4,523,771	4,159,796	4,752,354	4,198,778	3,726,191	2,549,029	2,623,578	41,668,642
3	Marginal Cost	75,127,964	81,140,513	86,220,158	108,153,708	85,216,172	125,308,457	101,623,816	115,672,296	101,484,464	106,159,182	56,970,798	60,027,465	1,103,104,993
4	Average Marginal Cost (\$/kWh)	2.958	3.239	3.129	3.092	2.221	2.770	2.443	2.434	2.417	2.849	2.235	2.288	2.647
5														
6	Off Peak Period													
7	System MWH Requirements	7,819,296	7,020,922	7,417,234	7,086,475	8,198,745	8,273,850	9,511,314	9,008,309	8,517,173	8,130,022	7,680,930	7,634,302	96,298,572
8	Marginal Cost	206,038,450	185,843,805	190,474,569	158,170,122	169,632,034	182,355,654	211,816,963	202,236,537	190,614,332	187,234,407	164,064,665	168,183,673	2,216,665,210
9	Average Marginal Cost (\$/kWh)	2.635	2.647	2.568	2.232	2.069	2.204	2.227	2.245	2.238	2.303	2.136	2.203	2.302
10														
11	Total Period													
12	System MWH Requirements	10,359,119	9,526,032	10,172,752	10,584,331	12,035,583	12,797,621	13,671,110	13,760,663	12,715,951	11,856,213	10,229,959	10,257,880	137,967,214
13	Marginal Cost	281,166,414	266,984,318	276,694,727	266,323,830	254,848,206	307,664,111	313,440,779	317,908,833	292,098,796	293,393,588	221,035,463	228,211,138	3,319,770,203
14	Average Marginal Cost (\$/kWh)	2.714	2.803	2.720	2.516	2.117	2.404	2.293	2.310	2.297	2.475	2.161	2.225	2.406
15														
16	Marginal Fuel Cost													
17	On-Peak Period													1.100
18	Off-Peak Period													0.957
19	Average													1.000
20														
21	Note: Totals may not add due to rounding.													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
DEVELOPMENT OF SEASONALLY DIFFERENTIATED TIME OF USE MULTIPLIERS

SCHEDULE: E1-D

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022						
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.		Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Total
1	On Peak Period					
2	System MWH Requirements	1,574,817	1,444,769	1,646,821	1,454,878	6,121,285
3	Marginal Cost	55,575,292	37,433,965	43,690,161	37,201,230	173,900,648
4	Average Marginal Cost (\$/kWh)	3.529	2.591	2.653	2.557	2.841
5						
6	Off Peak Period					
7	System MWH Requirements	11,222,804	12,226,341	12,113,842	11,261,073	46,824,060
8	Marginal Cost	251,615,266	275,337,199	273,893,968	254,387,639	1,055,234,072
9	Average Marginal Cost (\$/kWh)	2.242	2.252	2.261	2.259	2.254
10						
11	Total Period					
12	System MWH Requirements	12,797,621	13,671,110	13,760,663	12,715,951	52,945,345
13	Marginal Cost	307,190,558	312,771,164	317,584,129	291,588,870	1,229,134,720
14	Average Marginal Cost (\$/kWh)	2.400	2.288	2.308	2.293	2.322
15						
16	Marginal Fuel Cost					
17	On-Peak Period					1.224
18	Off-Peak Period					0.971
19	Average					1.000
20						
21	Note: Totals may not add due to rounding.					

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
FUEL RECOVER FACTORS BY RATE GROUP

SCHEDULE: E1-E

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	GROUPS	RATE SCHEDULE	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	A	RS-1 first 1,000 kWh	3.132	1.00291	2.822
2	A	RS-1 all additional kWh	3.132	1.00291	3.822
3					
4	A	GS-1, SL-2, GSCU-1, WIES-1	3.132	1.00291	3.141
5					
6	A-1	SL-1, OL-1, PL-1 ⁽¹⁾	3.069	1.00291	3.078
7					
8	B	GSD-1	3.132	1.00284	3.141
9					
10	C	GSLD-1, CS-1	3.132	1.00173	3.137
11					
12	D	GSLD-2, CS-2, OS-2, MET	3.132	0.99371	3.112
13					
14	E	GSLD-3, CS-3	3.132	0.97168	3.043
15					
16	A	GST-1 On-Peak	3.445	1.00291	3.455
17	A	GST-1 Off-Peak	2.997	1.00291	3.006
18					
19	A	RTR-1 On-Peak			0.314
20	A	RTR-1 Off-Peak			(0.135)
21					
22	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	3.445	1.00284	3.455
23	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.997	1.00284	3.006
24					
25	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	3.445	1.00173	3.451
26	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.997	1.00173	3.002
27					
28	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	3.445	0.99399	3.424
29	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.997	0.99399	2.979
30					
31	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	3.445	0.97168	3.347
32	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.997	0.97168	2.912
33					
34	F	CILC-1(D), ISST-1(D) On-Peak	3.445	0.99429	3.425
35	F	CILC-1(D), ISST-1(D) Off-Peak	2.997	0.99429	2.980
36					
37	⁽¹⁾ Weighted average 16% On-peak and 84% off-peak				
38	Note: Totals may not add due to rounding.				

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER

SCHEDULE: E1-E

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	GROUPS	RATE SCHEDULE	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	B	GSD(T)-1 On-Peak	3.834	1.00284	3.845
2	B	GSD(T)-1 Off-Peak	3.041	1.00284	3.050
3					
4	C	GSLD(T)-1 On-Peak	3.834	1.00173	3.841
5	C	GSLD(T)-1 Off-Peak	3.041	1.00173	3.046
6					
7	D	GSLD(T)-2 On-Peak	3.834	0.99399	3.811
8	D	GSLD(T)-2 Off-Peak	3.041	0.99399	3.023
9					
10	Note: Totals may not add due to rounding.				

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ENERGY LOSSES BY RATE CLASS

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.		Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	<u>RS(T)-1</u>						
2	Secondary	65,308,764	1.04908	68,514,089	0.95322	3,205,325	
3	TOTAL	65,308,764	1.04908	68,514,089	0.95322	3,205,325	1.00291
4							
5	<u>CILC-1D</u>						
6	Primary	1,057,248	1.02744	1,086,259	0.97329	29,011	
7	Secondary	1,477,761	1.04908	1,550,289	0.95322	72,528	
8	TOTAL	2,535,009	1.04005	2,636,548	0.96149	101,539	0.99429
9							
10	<u>CILC-1G</u>						
11	Primary	1,911	1.02744	1,964	0.97329	52	
12	Secondary	110,267	1.04908	115,679	0.95322	5,412	
13	TOTAL	112,179	1.04871	117,643	0.95355	5,464	1.00256
14							
15	<u>CILC-1T</u>						
16	Transmission	1,504,332	1.01641	1,529,015	0.98386	24,683	
17	TOTAL	1,504,332	1.01641	1,529,015	0.98386	24,683	0.97168
18							
19	<u>GS(T)-1</u>						
20	Secondary	8,367,598	1.04908	8,778,276	0.95322	410,678	
21	TOTAL	8,367,598	1.04908	8,778,276	0.95322	410,678	1.00291
22							
23	<u>GSCU-1</u>						
24	Secondary	69,407	1.04908	72,813	0.95322	3,406	
25	TOTAL	69,407	1.04908	72,813	0.95322	3,406	1.00291
26							
27	<u>GSD(T)-1</u>						
28	Primary	103,350	1.02744	106,186	0.97329	2,836	
29	Secondary	28,189,449	1.04908	29,572,974	0.95322	1,383,525	
30	TOTAL	28,292,799	1.04900	29,679,160	0.95329	1,386,361	1.00284
31							
32	<u>GSLD(T)-1</u>						
33	Primary	593,509	1.02744	609,795	0.97329	16,286	
34	Secondary	9,741,330	1.04908	10,219,431	0.95322	478,100	
35	TOTAL	10,334,839	1.04784	10,829,225	0.95435	494,386	1.00173
36							
37	<u>GSLD(T)-2</u>						
38	Primary	1,649,662	1.02744	1,694,929	0.97329	45,267	
39	Secondary	2,175,305	1.04908	2,282,068	0.95322	106,763	
40	TOTAL	3,824,967	1.03975	3,976,997	0.96177	152,030	0.99399
41							
42	<u>GSLD(T)-3</u>						
43	Transmission	960,683	1.01641	976,446	0.98386	15,763	
44	TOTAL	960,683	1.01641	976,446	0.98386	15,763	0.97168
45							

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ENERGY LOSSES BY RATE CLASS

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.		Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
46	<u>MET</u>						
47	Primary	84,965	1.02744	87,297	0.97329	2,331	
48	TOTAL	84,965	1.02744	87,297	0.97329	2,331	0.98223
49							
50	<u>OL-1</u>						
51	Secondary	90,628	1.04908	95,076	0.95322	4,448	
52	TOTAL	90,628	1.04908	95,076	0.95322	4,448	1.00291
53							
54	<u>OS-2</u>						
55	Primary	9,900	1.02744	10,172	0.97329	272	
56	TOTAL	9,900	1.02744	10,172	0.97329	272	0.98223
57							
58	<u>SL-1</u>						
59	Secondary	452,662	1.04908	474,878	0.95322	22,216	
60	TOTAL	452,662	1.04908	474,878	0.95322	22,216	1.00291
61							
62	<u>SL-2</u>						
63	Secondary	37,677	1.04908	39,527	0.95322	1,849	
64	TOTAL	37,677	1.04908	39,527	0.95322	1,849	1.00291
65							
66	<u>SL-1M</u>						
67	Secondary	26,566	1.04908	27,870	0.95322	1,304	
68	TOTAL	26,566	1.04908	27,870	0.95322	1,304	1.00291
69							
70	<u>SL-2M</u>						
71	Secondary	3,001	1.04908	3,148	0.95322	147	
72	TOTAL	3,001	1.04908	3,148	0.95322	147	1.00291
73							
74	<u>SST-DST</u>						
75	Primary	1,411	1.02744	1,449	0.97329	39	
76	TOTAL	1,411	1.02744	1,449	0.97329	39	0.98223
77							
78	<u>SST-TST</u>						
79	Transmission	65,703	1.01641	66,781	0.98386	1,078	
80	TOTAL	65,703	1.01641	66,781	0.98386	1,078	0.97168
81							
82	TOTAL FPSC						
83	TOTAL	122,083,090	1.04778	127,916,410	0.95440	5,833,320	1.00167
84							
85	<u>FKEC</u>						
86	Transmission	808,284	1.01641	821,546	0.98386	13,262	
87	TOTAL	808,284	1.01641	821,546	0.98386	13,262	0.97168
88							
89	<u>FPUC (INT)</u>						
90	Transmission	102,858	1.01641	104,545	0.98386	1,688	
91	TOTAL	102,858	1.01641	104,545	0.98386	1,688	0.97168

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ENERGY LOSSES BY RATE CLASS

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.		Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
92							
93	<u>FPUC (PEAK)</u>						
94	Transmission	54,048	1.01641	54,935	0.98386	887	
95	TOTAL	54,048	1.01641	54,935	0.98386	887	0.97168
96							
97	<u>HOMESTEAD</u>						
98	Transmission	31,981	1.01641	32,506	0.98386	525	
99	TOTAL	31,981	1.01641	32,506	0.98386	525	0.97168
100							
101	<u>LCEC</u>						
102	Transmission	4,411,751	1.01641	4,484,138	0.98386	72,388	
103	TOTAL	4,411,751	1.01641	4,484,138	0.98386	72,388	0.97168
104							
105	<u>MOORE HAVEN</u>						
106	Transmission	17,601	1.01641	17,890	0.98386	289	
107	TOTAL	17,601	1.01641	17,890	0.98386	289	0.97168
108							
109	<u>NEW SMRYNA BCH (PEAK)</u>						
110	Transmission	4,942	1.01641	5,023	0.98386	81	
111	TOTAL	4,942	1.01641	5,023	0.98386	81	0.97168
112							
113	<u>NEW SMRYNA BCH</u>						
114	Transmission	17,888	1.01641	18,182	0.98386	294	
115	TOTAL	17,888	1.01641	18,182	0.98386	294	0.97168
116							
117	<u>QUINCY</u>						
118	Transmission	100,235	1.01641	101,879	0.98386	1,645	
119	TOTAL	100,235	1.01641	101,879	0.98386	1,645	0.97168
120							
121	<u>WAUCHULA</u>						
122	Transmission	64,576	1.01641	65,635	0.98386	1,060	
123	TOTAL	64,576	1.01641	65,635	0.98386	1,060	0.97168
124							
125	<u>HOMESTEAD (INT)</u>						
126	Transmission	231,349	1.01641	235,145	0.98386	3,796	
127	TOTAL	231,349	1.01641	235,145	0.98386	3,796	0.97168
128							
129	<u>NEW SMYRNA BCH (INT)</u>						
130	Transmission	315	1.01641	320	0.98386	5	
131	TOTAL	315	1.01641	320	0.98386	5	0.97168
132							
133	<u>TOTAL FERC</u>						
134	TOTAL	7,208,970	1.01641	7,327,254	0.98386	118,284	0.97168
135							
136	<u>TOTAL COMPANY</u>						
137	TOTAL	129,292,060	1.04603	135,243,664	0.95599	5,951,604	1.00000

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ENERGY LOSSES BY RATE CLASS

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.		Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
138							
139	<u>COMPANY USE</u>						
140	Secondary	149,147	1.04908	156,467	0.95322	7,320	
141							
142	<u>TOTAL FPL</u>						
143	TOTAL	129,441,207	1.04604	135,400,131	0.95599	5,958,924	1.00000
144							
145	<u>G - FPU (INT)</u>						
146	Transmission	183,049	1.01641	186,053	0.98386	3,003	
147	TOTAL	183,049	1.01641	186,053	0.98386	3,003	0.97168
148							
149	<u>G - FPU (PEAK)</u>						
150	Transmission	106,712	1.01641	108,463	0.98386	1,751	
151	TOTAL	106,712	1.01641	108,463	0.98386	1,751	0.97168
152							
153	<u>JEA (INT)</u>						
154	Transmission	1,073,382	1.01641	1,090,994	0.98386	17,612	
155	TOTAL	1,073,382	1.01641	1,090,994	0.98386	17,612	0.97168
156							

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ENERGY LOSSES BY RATE CLASS GROUP

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	RATE CLASS GROUP	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	GSD-1/GSDT-1/HLFT-1/SDTR-1/CILC-1G	28,404,978	1.048999	29,796,803	0.953289	1,391,826	1.00284
2	GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	10,334,839	1.047837	10,829,225	0.954347	494,386	1.00173
3	GSLD2/GSLDT2/CS2/CST2/HLFT3	3,824,967	1.039747	3,976,997	0.961773	152,030	0.99399
4	GSLD3/GSLDT3/CS3/CST3	960,683	1.016408	976,446	0.983857	15,763	0.97168
5	GSLDT-2/CS-2/HLFT-3/SDTR-3/OS-2/MET	3,919,832	1.039449	4,074,465	0.962048	154,633	0.99371
6	OL1/SL1/SL1M/PL1/OS/II	569,856	1.049080	597,824	0.953217	27,968	1.00291

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
RS-1 INVERTED RATE COMPUTATION

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Inverted Rate	RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	44,348,224,920	0.02822	\$1,251,378,110	2.822
2	All Additional KWH	20,801,769,206	0.03822	\$794,983,206	3.822
3	Total KWH	<u>65,149,994,125</u>		<u>\$2,046,361,315</u>	
4					
5	Avg Fuel Factor	3.132			
6	RS-1 Loss Multiplier	1.00291			
7	Average Fuel Factor	<u>3.141</u>			
8	Target Fuel Revenues	<u>\$2,046,361,315</u>			

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
MONTHLY COST RECOVERY FACTOR

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	2022
1	Fuel Costs & Net Power Transactions													
2	Fuel Cost of System Net Generation (E3)	302,891,139	271,528,523	286,789,358	263,681,074	288,218,501	314,758,561	316,074,364	320,247,763	305,114,487	283,308,095	240,841,160	249,531,482	3,442,984,508
3	Rail Car Lease (Cedar Bay/Indiantown/Daniel)	172,112	172,112	169,439	172,112	171,221	172,112	171,221	172,112	172,112	171,221	172,112	171,221	2,059,102
4	Fuel Cost of Stratified Sales	(2,012,393)	(5,282,548)	(4,584,177)	(4,222,196)	(4,330,696)	(4,851,196)	(5,191,979)	(5,307,961)	(5,159,594)	(4,578,907)	(4,399,347)	(4,207,279)	(54,128,274)
5	Fuel Cost of Power Sold (Per E6)	(20,834,855)	(17,400,379)	(18,568,277)	(18,147,622)	(13,801,570)	(23,010,022)	(3,407,763)	(3,733,930)	(3,094,381)	(3,267,278)	(5,072,119)	(4,886,333)	(135,224,529)
6	Gains from Off-System Sales (E6)	(3,840,601)	(3,306,164)	(1,639,047)	(1,869,543)	(1,762,340)	(1,638,340)	(1,388,351)	(1,406,703)	(1,297,544)	(1,189,467)	(1,726,103)	(1,640,732)	(22,704,934)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	15,656,266	12,887,070	22,673,446	13,028,020	18,985,891	21,784,657	18,961,732	19,376,752	18,997,350	13,780,258	19,057,667	18,709,333	213,898,442
8	Energy Payments to Qualifying Facilities (E8)	1,815,148	1,903,389	2,266,916	2,152,064	2,329,066	2,293,358	2,280,045	2,209,111	2,031,423	2,074,109	1,804,540	1,634,738	24,793,908
9	Energy Cost of Economy Purchases (Per E9)	893,533	402,174	1,022,878	568,276	3,588,884	3,839,984	1,188,540	443,610	1,260,000	1,128,400	0	0	14,336,279
10		294,740,348	260,904,176	288,130,535	255,362,186	293,398,957	313,349,114	328,687,808	332,000,754	318,023,853	291,426,431	250,677,910	259,312,429	3,486,014,500
11	Incremental Optimization Costs													
12	Incremental Personnel, Software, and Hardware Costs	39,038	34,215	37,431	35,823	39,038	35,823	37,431	39,038	34,215	39,038	37,431	35,823	444,343
13	Var. Power Plant O&M Costs Attributable to Off-Sys Sales (E6)	158,559	168,835	108,309	106,116	91,280	80,008	63,686	69,192	61,632	57,586	104,688	98,654	1,168,545
14	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	(2,359)	(2,573)	(9,002)	(9,388)	(64,635)	(62,435)	(21,130)	(7,886)	(24,192)	(20,832)	(0)	(0)	(224,432)
15		195,238	200,477	136,738	132,551	65,683	53,395	79,987	100,344	71,655	75,792	142,119	134,477	1,388,456
16	Adjustments to Fuel Cost													
17	Energy Imbalance Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Other O&M Expense	0	3,972	0	26,991	239,903	276,254	0	0	0	0	0	0	547,119
19	Inventory Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
20		0	3,972	0	26,991	239,903	276,254	0	0	0	0	0	0	547,119
21														
22	Adjusted Total Fuel Costs & Net Power Transactions	294,935,586	261,108,625	288,267,273	255,521,727	293,704,543	313,678,762	328,767,795	332,101,098	318,095,508	291,502,223	250,820,028	259,446,906	3,487,950,075
23														
24	System MWH Sales (Excluding Stratified Sales)	9,774,943	8,853,332	8,912,612	9,497,192	10,307,493	11,688,756	12,500,179	12,724,042	12,474,498	11,344,935	9,974,663	9,337,188	127,389,834
25	Recovery Factors													
26	Cost per kWh	3.0173	2.9493	3.2344	2.6905	2.8494	2.6836	2.6301	2.6100	2.5500	2.5694	2.5146	2.7786	2.7380
27	Jurisdictional Loss Multiplier	1.001672	1.001672	1.001672	1.001672	1.001672	1.001672	1.001672	1.001672	1.001672	1.001672	1.001672	1.001672	1.001672
28	Jurisdictional Cost	3.0223	2.9542	3.2398	2.6950	2.8542	2.6881	2.6345	2.6144	2.5542	2.5737	2.5188	2.7833	2.7426
29	True-up (cents/kWh)	0.31350	0.34770	0.34500	0.32390	0.29850	0.26300	0.24570	0.24180	0.24690	0.27140	0.31050	0.32980	0.28990
30	Total (cents/kWh)	3.3358	3.3019	3.5848	3.0189	3.1527	2.9511	2.8802	2.8562	2.8011	2.8451	2.8293	3.1131	3.0325
31	Revenue Tax Factor	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
32	Recovery Factor adjusted for Taxes	3.3358	3.3019	3.5848	3.0189	3.1527	2.9511	2.8802	2.8562	2.8011	2.8451	2.8293	3.1131	3.0325
33	GPIF	0.0042	0.0047	0.0046	0.0043	0.0040	0.0035	0.0033	0.0032	0.0033	0.0036	0.0042	0.0044	0.0039
34	Asset Optimization, Net of Revenue Taxes	0.0031	0.0034	0.0034	0.0032	0.0030	0.0026	0.0024	0.0024	0.0024	0.0027	0.0031	0.0033	0.0029
35	SolarTogether - Subscription Credit	0.0633	0.0876	0.0887	0.1183	0.1152	0.1069	0.0864	0.0890	0.0881	0.0870	0.0983	0.0880	0.0930
36	Recovery Factor Including GPIF and Incentive	3.4064	3.3976	3.6815	3.1447	3.2749	3.0641	2.9723	2.9508	2.8949	2.9384	2.9349	3.2088	3.1323
37														
38	Recovery Factor Rounded to .001 (¢/KWh)	3.406	3.398	3.682	3.145	3.275	3.064	2.972	2.951	2.895	2.938	2.935	3.209	3.132
39														
40	Note: Totals may not add due to rounding.													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022														
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	FCR - E3	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1	Fuel Cost of System Net Generation (\$)													
2	Light Oil	0	19,286	0	307,816	0	875,637	166,712	79,431	19,453	369,486	0	0	1,837,822
3	Coal	9,932,480	8,803,748	8,263,185	5,485,468	5,920,555	8,084,800	0	0	682,226	542,618	0	0	47,715,079
4	Gas	279,423,584	250,480,261	267,500,833	246,205,997	269,186,898	293,110,013	302,796,604	307,057,283	295,025,258	269,846,865	228,490,165	236,768,786	3,245,892,546
5	Nuclear	13,535,074	12,225,228	11,025,340	11,681,793	13,111,049	12,688,111	13,111,049	13,111,049	9,387,551	12,549,126	12,350,995	12,762,696	147,539,060
6	Subtotal Fuel Cost of System Net Generation (\$)	302,891,139	271,528,523	286,789,358	263,681,074	288,218,501	314,758,561	316,074,364	320,247,763	305,114,487	283,308,095	240,841,160	249,531,482	3,442,984,508
7														
8	System Net Generation (MWh)													
9	Light Oil	0	108	0	1,639	0	9,765	1,581	949	232	2,041	0	0	16,316
10	Coal	369,019	324,425	306,818	198,353	209,169	293,248	0	0	23,558	18,722	0	0	1,743,311
11	Gas	6,848,858	6,217,400	6,936,354	7,116,731	8,167,055	9,201,717	9,671,064	9,813,442	9,462,168	8,183,109	6,521,869	6,523,206	94,662,974
12	Nuclear	2,602,438	2,350,589	2,197,126	2,280,603	2,540,294	2,458,349	2,540,294	2,540,294	1,815,626	2,494,385	2,518,488	2,602,438	28,940,921
13	Solar	504,817	591,002	759,211	792,950	835,467	712,966	754,197	722,941	663,607	673,105	585,294	525,484	8,121,040
14	Subtotal System Net Generation (MWh)	10,325,132	9,483,524	10,199,509	10,390,275	11,751,984	12,676,045	12,967,136	13,077,625	11,965,192	11,371,362	9,625,651	9,651,128	133,484,562
15														
16	Units of Fuel Burned (Unit) ⁽¹⁾													
17	Light Oil		203		3,239		10,905	1,962	1,001	245	3,891			21,445
18	Coal	210,988	188,114	175,967	116,188	125,888	173,189			15,459	12,293			1,018,086
19	Gas	46,874,793	42,630,675	47,573,298	49,026,504	56,384,590	64,090,543	65,114,541	66,136,763	63,735,113	55,478,678	43,749,916	43,889,844	644,685,258
20	Nuclear	27,047,123	24,429,659	22,809,140	24,266,978	27,046,432	26,173,966	27,046,432	27,046,432	19,386,880	26,561,639	26,174,634	27,047,123	305,036,436
21														
22														
23	BTU Burned (MMBTU)													
24	Light Oil	0	1,183	0	18,881	0	63,575	11,436	5,835	1,429	22,685	0	0	125,024
25	Coal	3,739,522	3,332,922	3,130,500	2,070,470	2,238,925	3,066,928	0	0	262,796	208,989	0	0	18,051,053
26	Gas	46,874,793	42,630,675	47,573,298	49,026,504	56,384,590	64,090,543	65,114,541	66,136,763	63,735,113	55,478,678	43,749,916	43,889,844	644,685,258
27	Nuclear	27,047,123	24,429,659	22,809,140	24,266,978	27,046,432	26,173,966	27,046,432	27,046,432	19,386,880	26,561,639	26,174,634	27,047,123	305,036,436
28	Subtotal BTU Burned (MMBTU)	77,661,438	70,394,439	73,512,937	75,382,833	85,669,947	93,395,013	92,172,409	93,189,030	83,386,218	82,271,991	69,924,550	70,936,967	967,897,771
29														
30	Fuel Cost per Unit (\$/Unit)													
31	Light Oil		95.0445		95.0464		80.2983	84.9886	79.3632	79.3639	94.9569			85.6995
32	Coal	47.0761	46.8002	46.9587	47.2120	47.0303	46.6819			44.1325	44.1387			46.8675
33	Gas	5.9611	5.8756	5.6229	5.0219	4.7741	4.5734	4.6502	4.6428	4.6289	4.8640	5.2226	5.3946	5.0348
34	Nuclear	0.5004	0.5004	0.4834	0.4814	0.4848	0.4848	0.4848	0.4848	0.4842	0.4725	0.4719	0.4719	0.4837
35														
36	Generation Mix (%)													
37	Light Oil	0%	0.00%	0%	0.02%	0%	0.08%	0.01%	0.01%	0.00%	0.02%	0%	0%	0.01%
38	Coal	3.57%	3.42%	3.01%	1.91%	1.78%	2.31%	0%	0%	0.20%	0.16%	0%	0%	1.31%
39	Gas	66.33%	65.56%	68.01%	68.49%	69.50%	72.59%	74.58%	75.04%	79.08%	71.96%	67.76%	67.59%	70.92%
40	Nuclear	25.20%	24.79%	21.54%	21.95%	21.62%	19.39%	19.59%	19.42%	15.17%	21.94%	26.16%	26.97%	21.68%
41	Solar	4.89%	6.23%	7.44%	7.63%	7.11%	5.62%	5.82%	5.53%	5.55%	5.92%	6.08%	5.44%	6.08%
42														
43	Fuel Cost per MMBTU (\$/MMBTU)													
44	Light Oil		16.3030		16.3030		13.7733	14.5778	13.6129	13.6129	16.2877			14.6998
45	Coal	2.6561	2.6415	2.6396	2.6494	2.6444	2.6361			2.5960	2.5964			2.6433
46	Gas	5.9611	5.8756	5.6229	5.0219	4.7741	4.5734	4.6502	4.6428	4.6289	4.8640	5.2226	5.3946	5.0348
47	Nuclear	0.5004	0.5004	0.4834	0.4814	0.4848	0.4848	0.4848	0.4848	0.4842	0.4725	0.4719	0.4719	0.4837
48														

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022														
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	FCR - E3	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1	BTU Burned per KWH (BTU/KWH)													
2	Light Oil	0	10,963	0	11,519	0	6,510	7,231	6,150	6,149	11,116	0	0	7,663
3	Coal	10,134	10,273	10,203	10,438	10,704	10,458	0	0	11,155	11,163	0	0	10,354
4	Gas	6,844	6,857	6,859	6,889	6,904	6,965	6,733	6,739	6,736	6,780	6,708	6,728	6,810
5	Nuclear	10,393	10,393	10,381	10,641	10,647	10,647	10,647	10,647	10,678	10,649	10,393	10,393	10,540
6														
7	Generated Fuel Cost per KWH (cents/KWH)													
8	Light Oil		17.8727		18.7798		8.9669	10.5415	8.3722	8.3708	18.1048			11.2642
9	Coal	2.6916	2.7136	2.6932	2.7655	2.8305	2.7570			2.8959	2.8983			2.7370
10	Gas	4.0799	4.0287	3.8565	3.4595	3.2960	3.1854	3.1310	3.1289	3.1179	3.2976	3.5034	3.6296	3.4289
11	Nuclear	0.5201	0.5201	0.5018	0.5122	0.5161	0.5161	0.5161	0.5161	0.5170	0.5031	0.4904	0.4904	0.5098
12	Subtotal Generated Fuel Cost per KWH (cents/KWH)	2.9335	2.8632	2.8118	2.5378	2.4525	2.4831	2.4375	2.4488	2.5500	2.4914	2.5021	2.5855	2.5793
13														
14														
15	⁽¹⁾ Fuel Units: Light Oil - BBLs, Coal - TONS, Gas - MMBTU, Nuclear - OTHER													
16	Note: Totals may not add due to rounding.													
17														
18														
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FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Jan - 2022												
2	Babcock Preserve ST Solar												
3	Solar		13,246					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,246	23.9%	N/A	23.9%	N/A						
5	Babcock PV Solar												
6	Solar		12,457					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,457	22.5%	N/A	22.5%	N/A						
8	Barefoot PV Solar												
9	Solar		12,659					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,659	22.8%	N/A	22.8%	N/A						
11	Blue Cypress PV Solar												
12	Solar		13,175					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,175	23.8%	N/A	23.8%	N/A						
14	Blue Heron ST Solar												
15	Solar		13,246					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,246	23.9%	N/A	23.9%	N/A						
17	Blue Indigo PV Solar												
18	Solar		11,522					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	15.6	11,522	99.0%	N/A	99.0%	N/A						
20	Blue Springs PV Solar												
21	Solar		9,115					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	12.3	9,115	100.0%	N/A	100.0%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		11,618					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	11,618	21.0%	N/A	21.0%	N/A						
26	CCEC 3												
27	Gas		392,968				6,746	2,651,087	1,000,000	2,651,087	15,835,740	4.03	5.97
28	Plant Unit Info	1,326.0	392,968	39.8%	93.4%	42.6%	6,746			2,651,087	15,835,740	4.03	
29	Citrus PV Solar												
30	Solar		12,537					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	12,537	22.6%	N/A	22.6%	N/A						
32	Coral Farms PV Solar												
33	Solar		13,003					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	13,003	23.5%	N/A	23.5%	N/A						
35	Cotton Creek PV Solar												

FLORIDA POWER & LIGHT COMPANY
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SCHEDULE: E4

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		11,633					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	15.6	11,633	100.0%	N/A	100.0%	N/A						
3	Dania Beach												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Daniel 1												
8	Coal		162,194				10,117	92,087	17,820,001	1,640,992	4,370,589	2.69	47.46
9	Plant Unit Info	502.0	162,194	43.4%	98.4%	73.4%	10,117			1,640,992	4,370,589	2.69	
10	Daniel 2												
11	Coal		167,853				9,998	94,172	17,819,999	1,678,143	4,469,536	2.66	47.46
12	Plant Unit Info	502.0	167,853	44.9%	100.0%	66.1%	9,998			1,678,143	4,469,536	2.66	
13	Desoto Solar												
14	Solar		3,151					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	3,151	16.9%	N/A	16.9%	N/A						
16	Discovery PV Solar												
17	Solar		10,311					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	10,311	18.6%	N/A	18.6%	N/A						
19	Echo River PV Solar												
20	Solar		12,535					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,535	22.6%	N/A	22.6%	N/A						
22	Egret PV Solar												
23	Solar		9,166					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	9,166	16.5%	N/A	16.5%	N/A						
25	Elder Branch PV Solar												
26	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Fort Drum PV Solar												
29	Solar		10,127					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	10,127	18.3%	N/A	18.3%	N/A						
31	Fort Myers 2												
32	Gas		746,806				6,994	5,223,033	1,000,000	5,223,033	31,199,793	4.18	5.97
33	Plant Unit Info	1,740.0	746,806	57.7%	93.8%	61.5%	6,994			5,223,033	31,199,793	4.18	
34	Fort Myers 3A												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	189.0	0	N/A	71.2%	N/A	N/A						
3	Fort Myers 3B												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	193.0	0	N/A	71.2%	N/A	N/A						
7	Fort Myers 3C												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		589				12,433	7,323	1,000,000	7,323	43,843	7.44	5.99
10	Plant Unit Info	221.0	589	0.4%	93.8%	0.4%	12,433			7,323	43,843	7.44	
11	Fort Myers 3D												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		818				10,623	8,690	1,000,000	8,690	51,803	6.33	5.96
14	Plant Unit Info	221.0	818	0.5%	93.8%	0.5%	10,623			8,690	51,803	6.33	
15	GCEC 4												
16	Gas		8,683				13,147	114,159	1,000,000	114,159	666,061	7.67	5.83
17	Plant Unit Info	78.0	8,683	15.0%	100.0%	15.0%	13,147			114,159	666,061	7.67	
18	GCEC 5												
19	Gas		10,604				13,147	139,410	1,000,000	139,410	813,392	7.67	5.83
20	Plant Unit Info	78.0	10,604	18.3%	99.9%	56.0%	13,147			139,410	813,392	7.67	
21	GCEC 6												
22	Gas		43,505				11,419	496,803	1,000,000	496,803	2,898,604	6.66	5.83
23	Plant Unit Info	315.0	43,505	18.6%	98.5%	29.2%	11,419			496,803	2,898,604	6.66	
24	GCEC 7												
25	Gas		86,517				11,723	1,014,200	1,000,000	1,014,200	5,917,367	6.84	5.83
26	Plant Unit Info	496.0	86,517	23.4%	98.8%	31.5%	11,723			1,014,200	5,917,367	6.84	
27	GCEC 8A												
28	Gas		3,800				9,986	37,947	1,000,000	37,947	221,401	5.83	5.83
29	Plant Unit Info	237.5	3,800	2.2%	100.0%	2.2%	9,986			37,947	221,401	5.83	
30	GCEC 8B												
31	Gas		3,621				9,986	36,159	1,000,000	36,159	210,968	5.83	5.83
32	Plant Unit Info	237.5	3,621	2.1%	100.0%	2.1%	9,986			36,159	210,968	5.83	
33	GCEC 8C												
34	Gas		3,129				9,986	31,250	1,000,000	31,250	182,330	5.83	5.83
35	Plant Unit Info	237.5	3,129	1.8%	100.0%	1.8%	9,986			31,250	182,330	5.83	

FLORIDA POWER & LIGHT COMPANY
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		3,134				9,986	31,296	1,000,000	31,296	182,598	5.83	5.83
3	Plant Unit Info	237.5	3,134	1.8%	100.0%	1.8%	9,986			31,296	182,598	5.83	
4	Ghost Orchid PV Solar												
5	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Grove PV Solar												
8	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
10	Hammock PV Solar												
11	Solar		13,687					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	13,687	24.7%	N/A	24.7%	N/A						
13	Hibiscus PV Solar												
14	Solar		12,074					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	12,074	21.8%	N/A	21.8%	N/A						
16	Horizon PV Solar												
17	Solar		13,108					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	13,108	23.7%	N/A	23.7%	N/A						
19	Immokalee PV Solar												
20	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
22	Indian River PV Solar												
23	Solar		13,165					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	13,165	23.8%	N/A	23.8%	N/A						
25	Interstate PV Solar												
26	Solar		12,665					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	12,665	22.9%	N/A	22.9%	N/A						
28	Lakeside PV Solar												
29	Solar		11,308					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	11,308	20.4%	N/A	20.4%	N/A						
31	Lauderdale 6A												
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	218.0	0	N/A	71.4%	N/A	N/A						
34	Lauderdale 6B												
35	Gas		0					0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	218.0	0	N/A	71.4%	N/A	N/A						
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	218.0	0	N/A	71.4%	N/A	N/A						
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	218.0	0	N/A	90.8%	N/A	N/A						
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
14	Loggerhead PV Solar												
15	Solar		13,304					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,304	24.0%	N/A	24.0%	N/A						
17	Magnolia PV Solar												
18	Solar		9,424					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	9,424	17.0%	N/A	17.0%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		474,343				6,931	3,287,545	1,000,000	3,287,545	19,471,026	4.10	5.92
30	Plant Unit Info	1,254.0	474,343	50.8%	93.9%	54.1%	6,931			3,287,545	19,471,026	4.10	
31	Manatee PV Solar												
32	Solar		12,567					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	12,567	22.7%	N/A	22.7%	N/A						
34	Martin 3												
35	Gas		167,292				7,296	1,220,548	1,000,000	1,220,548	7,231,107	4.32	5.92

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	492.0	167,292	45.7%	93.4%	48.7%	7,296			1,220,548	7,231,107	4.32	
2	Martin 4												
3	Gas		0					0	0	0	0	0.00	0.00
4	Plant Unit Info	492.0	0	N/A	93.9%	N/A	N/A						
5	Martin 8												
6	Gas		29,423				8,130	239,217	1,000,000	239,217	1,418,385	4.82	5.93
7	Plant Unit Info	1,258.0	29,423	3.1%	93.5%	3.4%	8,130			239,217	1,418,385	4.82	
8	Martin 8 Solar												
9	Solar		7,409					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	7,409	18.1%	N/A	18.1%	N/A						
11	Miami-Dade PV Solar												
12	Solar		13,154					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,154	23.7%	N/A	23.7%	N/A						
14	Nassau PV Solar												
15	Solar		8,754					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	8,754	15.8%	N/A	15.8%	N/A						
17	Northern Preserve ST Solar												
18	Solar		11,513					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	11,513	20.8%	N/A	20.8%	N/A						
20	OKEECHOBEE 1												
21	Gas		964,140				6,300	6,074,404	1,000,000	6,074,404	36,402,681	3.78	5.99
22	Plant Unit Info	1,640.0	964,140	79.0%	93.0%	85.0%	6,300			6,074,404	36,402,681	3.78	
23	Okeechobee PV Solar												
24	Solar		12,645					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	12,645	22.8%	N/A	22.8%	N/A						
26	Orange Blossom PV Solar												
27	Solar		11,097					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	11,097	20.0%	N/A	20.0%	N/A						
29	Palm Bay PV Solar												
30	Solar		10,924					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	10,924	19.7%	N/A	19.7%	N/A						
32	Pea Ridge												
33	Gas		5,712				15,000	85,680	1,000,000	85,680	516,773	9.05	6.03
34	Plant Unit Info	8.0	5,712	96.0%	100.0%	96.0%	15,000			85,680	516,773	9.05	
35	PEEC												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		858,134				6,337	5,438,319	1,000,000	5,438,319	32,485,407	3.79	5.97
3	Plant Unit Info	1,283.0	858,134	89.9%	93.0%	96.7%	6,337			5,438,319	32,485,407	3.79	
4	Pelican PV Solar												
5	Solar		11,097					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	11,097	20.0%	N/A	20.0%	N/A						
7	Perdido												
8	Gas		2,097				9,900	20,760	1,000,000	20,760	104,626	4.99	5.04
9	Plant Unit Info	3.0	2,097	94.0%	100.0%	94.0%	9,900			20,760	104,626	4.99	
10	Pioneer Trail PV Solar												
11	Solar		12,138					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	12,138	21.9%	N/A	21.9%	N/A						
13	Riviera 5												
14	Gas		497,305				6,669	3,316,775	1,000,000	3,316,775	19,870,634	4.00	5.99
15	Plant Unit Info	1,326.0	497,305	50.4%	93.4%	54.0%	6,669			3,316,775	19,870,634	4.00	
16	Rodeo PV Solar												
17	Solar		10,524					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	10,524	19.0%	N/A	19.0%	N/A						
19	Sabal Palm PV Solar												
20	Solar		11,241					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	11,241	20.3%	N/A	20.3%	N/A						
22	Sanford 4												
23	Gas		5,458				8,637	47,141	1,000,000	47,141	281,017	5.15	5.96
24	Plant Unit Info	1,192.0	5,458	0.6%	94.1%	0.7%	8,637			47,141	281,017	5.15	
25	Sanford 5												
26	Gas		397,245				6,940	2,756,998	1,000,000	2,756,998	16,469,249	4.15	5.97
27	Plant Unit Info	1,192.0	397,245	44.8%	94.1%	47.6%	6,940			2,756,998	16,469,249	4.15	
28	Sawgrass PV Solar												
29	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
31	Scherer 3												
32	Coal		38,971				10,787	24,729	17,000,000	420,387	1,092,356	2.80	44.17
33	Plant Unit Info	860.0	38,971	6.1%	99.6%	46.5%	10,787			420,387	1,092,356	2.80	
34	Scherer 4												
35	Coal											N/A	0.00

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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		442,966				6,848	3,033,430	1,000,000	3,033,430	18,295,932	4.13	6.03
4	Plant Unit Info	694.7	442,966	85.7%	91.3%	88.0%	6,848			3,033,430	18,295,932	4.13	
5	Smith A												
6	Plant Unit Info	40.0	0	N/A	98.4%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		13,849					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	13,849	25.0%	N/A	25.0%	N/A						
10	Space Coast												
11	Solar		1,280					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,280	17.2%	100.0%	17.2%	N/A						
13	St Lucie 1												
14	Nuclear		727,591				10,328	7,514,787	1,000,000	7,514,787	3,654,441	0.50	0.49
15	Plant Unit Info	1,003.0	727,591	97.5%	97.3%	100.0%	10,328			7,514,787	3,654,441	0.50	
16	St Lucie 2												
17	Nuclear		623,512				10,257	6,395,178	1,000,000	6,395,178	2,732,020	0.44	0.43
18	Plant Unit Info	859.6	623,512	97.5%	97.5%	100.0%	10,257			6,395,178	2,732,020	0.44	
19	Sundew PV Solar												
20	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		11,842					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	11,842	21.4%	N/A	21.4%	N/A						
25	Sweetbay PV Solar												
26	Solar		11,836					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	11,836	21.4%	N/A	21.4%	N/A						
28	Trailside PV Solar												
29	Solar		9,697					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	9,697	17.5%	N/A	17.5%	N/A						
31	Turkey Point 3												
32	Nuclear		623,100				10,541	6,568,284	1,000,000	6,568,284	3,258,526	0.52	0.50
33	Plant Unit Info	859.0	623,100	97.5%	97.5%	100.0%	10,541			6,568,284	3,258,526	0.52	
34	Turkey Point 4												
35	Nuclear		628,234				10,456	6,568,874	1,000,000	6,568,874	3,890,087	0.62	0.59

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	866.0	628,234	97.5%	97.3%	100.0%	10,456			6,568,874	3,890,087	0.62	
2	Turkey Point 5												
3	Gas		475,715				6,933	3,298,015	1,000,000	3,298,015	19,702,740	4.14	5.97
4	Plant Unit Info	1,294.0	475,715	49.4%	93.9%	52.6%	6,933			3,298,015	19,702,740	4.14	
5	Twin Lakes ST Solar												
6	Solar		11,306					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	11,306	20.4%	N/A	20.4%	N/A						
8	Union Springs PV Solar												
9	Solar		9,531					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	9,531	17.2%	N/A	17.2%	N/A						
11	WCEC 01												
12	Gas		164,657				6,940	1,142,749	1,000,000	1,142,749	6,770,606	4.11	5.92
13	Plant Unit Info	1,248.0	164,657	17.7%	93.7%	18.9%	6,940			1,142,749	6,770,606	4.11	
14	WCEC 02												
15	Gas		493,886				6,740	3,328,582	1,000,000	3,328,582	19,713,197	3.99	5.92
16	Plant Unit Info	1,248.0	493,886	53.2%	93.2%	56.8%	6,740			3,328,582	19,713,197	3.99	
17	WCEC 03												
18	Gas		566,312				6,698	3,793,273	1,000,000	3,793,273	22,466,302	3.97	5.92
19	Plant Unit Info	1,254.0	566,312	60.7%	93.7%	64.8%	6,698			3,793,273	22,466,302	3.97	
20	Wildflower PV Solar												
21	Solar		13,496					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	13,496	24.4%	N/A	24.4%	N/A						
23	Willow PV Solar												
24	Solar		10,681					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	10,681	19.3%	N/A	19.3%	N/A						
26	System Totals												
27	Plant Unit Info	31,306	10,325,132				7,522			77,661,438	302,891,139	2.93	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Feb - 2022												
2	Babcock Preserve ST Solar												
3	Solar		13,531					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,531	27.0%	N/A	27.0%	N/A						
5	Babcock PV Solar												
6	Solar		12,520					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,520	25.0%	N/A	25.0%	N/A						
8	Barefoot PV Solar												
9	Solar		12,676					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,676	25.3%	N/A	25.3%	N/A						
11	Blue Cypress PV Solar												
12	Solar		13,303					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,303	26.6%	N/A	26.6%	N/A						
14	Blue Heron ST Solar												
15	Solar		13,531					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,531	27.0%	N/A	27.0%	N/A						
17	Blue Indigo PV Solar												
18	Solar		11,865					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	17.8	11,865	99.0%	N/A	99.0%	N/A						
20	Blue Springs PV Solar												
21	Solar		9,445					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	14.1	9,445	100.0%	N/A	100.0%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		12,340					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	12,340	24.7%	N/A	24.7%	N/A						
26	CCEC 3												
27	Gas		328,948				6,738	2,216,439	1,000,000	2,216,439	13,052,318	3.97	5.89
28	Plant Unit Info	1,326.0	328,948	36.9%	76.8%	48.1%	6,738			2,216,439	13,052,318	3.97	
29	Citrus PV Solar												
30	Solar		12,263					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	12,263	24.5%	N/A	24.5%	N/A						
32	Coral Farms PV Solar												
33	Solar		13,305					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	13,305	26.6%	N/A	26.6%	N/A						
35	Cotton Creek PV Solar												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		11,364					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	16.9	11,364	100.0%	N/A	100.0%	N/A						
3	Dania Beach												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Daniel 1												
8	Coal		140,832				10,184	80,487	17,820,000	1,434,283	3,796,781	2.70	47.17
9	Plant Unit Info	502.0	140,832	41.8%	100.0%	41.8%	10,184			1,434,283	3,796,781	2.70	
10	Daniel 2												
11	Coal		149,050				10,059	84,135	17,820,000	1,499,281	3,968,840	2.66	47.17
12	Plant Unit Info	502.0	149,050	44.2%	100.0%	62.1%	10,059			1,499,281	3,968,840	2.66	
13	Desoto Solar												
14	Solar		3,239					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	3,239	19.3%	N/A	19.3%	N/A						
16	Discovery PV Solar												
17	Solar		10,385					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	10,385	20.7%	N/A	20.7%	N/A						
19	Echo River PV Solar												
20	Solar		12,997					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,997	26.0%	N/A	26.0%	N/A						
22	Egret PV Solar												
23	Solar		9,971					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	9,971	19.9%	N/A	19.9%	N/A						
25	Elder Branch PV Solar												
26	Solar		13,296					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	13,296	26.6%	N/A	26.6%	N/A						
28	Fort Drum PV Solar												
29	Solar		10,165					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	10,165	20.3%	N/A	20.3%	N/A						
31	Fort Myers 2												
32	Gas		684,558				7,022	4,807,203	1,000,000	4,807,203	28,305,742	4.13	5.89
33	Plant Unit Info	1,740.0	684,558	58.6%	93.8%	62.4%	7,022			4,807,203	28,305,742	4.13	
34	Fort Myers 3A												
35	Light Oil		108				10,963	203	5,829,884	1,183	19,286	17.87	95.04

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		1,608				10,963	17,629	1,000,000	17,629	104,234	6.48	5.91
2	Plant Unit Info	189.0	1,716	1.4%	93.8%	1.4%	10,963			18,812	123,520	7.20	
3	Fort Myers 3B												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	193.0	0	N/A	93.8%	N/A	N/A						
7	Fort Myers 3C												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		2,599				11,041	28,695	1,000,000	28,695	169,109	6.51	5.89
10	Plant Unit Info	221.0	2,599	1.8%	68.8%	2.6%	11,041			28,695	169,109	6.51	
11	Fort Myers 3D												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		2,952				10,732	31,680	1,000,000	31,680	187,118	6.34	5.91
14	Plant Unit Info	221.0	2,952	2.0%	68.8%	2.9%	10,732			31,680	187,118	6.34	
15	GCEC 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	78.0	0	N/A	100.0%	N/A	N/A						
18	GCEC 5												
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	78.0	0	N/A	99.9%	60.3%	N/A						
21	GCEC 6												
22	Gas		57,539				11,424	657,302	1,000,000	657,302	3,779,368	6.57	5.75
23	Plant Unit Info	315.0	57,539	27.2%	98.4%	27.5%	11,424			657,302	3,779,368	6.57	
24	GCEC 7												
25	Gas		46,980				11,772	553,042	1,000,000	553,042	3,179,890	6.77	5.75
26	Plant Unit Info	496.0	46,980	14.1%	80.8%	20.0%	11,772			553,042	3,179,890	6.77	
27	GCEC 8A												
28	Gas		143				9,986	1,429	1,000,000	1,429	8,218	5.74	5.75
29	Plant Unit Info	237.5	143	0.1%	100.0%	0.1%	9,986			1,429	8,218	5.74	
30	GCEC 8B												
31	Gas		0					0	0	0	0	0.00	0.00
32	Plant Unit Info	237.5	0	N/A	100.0%	N/A	N/A						
33	GCEC 8C												
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	237.5	0	N/A	100.0%	N/A	N/A						

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		0					0	0	0	0	0.00	0.00
3	Plant Unit Info	237.5	0	N/A	100.0%	N/A	N/A						
4	Ghost Orchid PV Solar												
5	Solar		12,364					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	12,364	24.7%	N/A	24.7%	N/A						
7	Grove PV Solar												
8	Solar		11,942					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	11,942	23.9%	N/A	23.9%	N/A						
10	Hammock PV Solar												
11	Solar		13,943					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	13,943	27.9%	N/A	27.9%	N/A						
13	Hibiscus PV Solar												
14	Solar		12,411					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	12,411	24.8%	N/A	24.8%	N/A						
16	Horizon PV Solar												
17	Solar		12,944					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	12,944	25.9%	N/A	25.9%	N/A						
19	Immokalee PV Solar												
20	Solar		12,540					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,540	25.1%	N/A	25.1%	N/A						
22	Indian River PV Solar												
23	Solar		13,293					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	13,293	26.6%	N/A	26.6%	N/A						
25	Interstate PV Solar												
26	Solar		12,816					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	12,816	25.6%	N/A	25.6%	N/A						
28	Lakeside PV Solar												
29	Solar		11,742					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	11,742	23.5%	N/A	23.5%	N/A						
31	Lauderdale 6A												
32	Gas		1,013				10,585	10,723	1,000,000	10,723	63,158	6.23	5.89
33	Plant Unit Info	218.0	1,013	0.7%	94.0%	0.7%	10,585			10,723	63,158	6.23	
34	Lauderdale 6B												
35	Gas		2,025				10,590	21,445	1,000,000	21,445	126,438	6.24	5.90

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	218.0	2,025	1.4%	94.0%	1.5%	10,590			21,445	126,438	6.24	
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		1,013				10,585	10,723	1,000,000	10,723	63,479	6.27	5.92
5	Plant Unit Info	218.0	1,013	0.7%	94.0%	0.7%	10,585			10,723	63,479	6.27	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		1,690				10,988	18,570	1,000,000	18,570	109,667	6.49	5.91
9	Plant Unit Info	218.0	1,690	1.2%	72.6%	1.6%	10,988			18,570	109,667	6.49	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		2,025				10,590	21,445	1,000,000	21,445	126,438	6.24	5.90
13	Plant Unit Info	218.0	2,025	1.4%	69.0%	2.0%	10,590			21,445	126,438	6.24	
14	Loggerhead PV Solar												
15	Solar		13,547					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,547	27.1%	N/A	27.1%	N/A						
17	Magnolia PV Solar												
18	Solar		10,092					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	10,092	20.2%	N/A	20.2%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		532,355				6,882	3,663,931	1,000,000	3,663,931	21,379,548	4.02	5.84
30	Plant Unit Info	1,254.0	532,355	63.2%	93.9%	67.3%	6,882			3,663,931	21,379,548	4.02	
31	Manatee PV Solar												
32	Solar		12,186					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	12,186	24.3%	N/A	24.3%	N/A						
34	Martin 3												
35	Gas		152,151				7,369	1,121,181	1,000,000	1,121,181	6,542,830	4.30	5.84

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	492.0	152,151	46.0%	93.4%	49.0%	7,369			1,121,181	6,542,830	4.30	
2	Martin 4												
3	Gas		19,290				7,981	153,952	1,000,000	153,952	896,151	4.65	5.82
4	Plant Unit Info	492.0	19,290	5.8%	93.9%	6.2%	7,981			153,952	896,151	4.65	
5	Martin 8												
6	Gas		177,953				7,077	1,259,445	1,000,000	1,259,445	7,331,580	4.12	5.82
7	Plant Unit Info	1,258.0	177,953	21.1%	93.5%	22.5%	7,077			1,259,445	7,331,580	4.12	
8	Martin 8 Solar												
9	Solar		8,484					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	8,484	23.0%	N/A	23.0%	N/A						
11	Miami-Dade PV Solar												
12	Solar		13,157					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,157	26.3%	N/A	26.3%	N/A						
14	Nassau PV Solar												
15	Solar		9,578					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	9,578	19.1%	N/A	19.1%	N/A						
17	Northern Preserve ST Solar												
18	Solar		11,761					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	11,761	23.5%	N/A	23.5%	N/A						
20	OKEECHOBEE 1												
21	Gas		777,181				6,347	4,932,464	1,000,000	4,932,464	29,185,216	3.76	5.92
22	Plant Unit Info	1,640.0	777,181	70.5%	93.0%	75.8%	6,347			4,932,464	29,185,216	3.76	
23	Okeechobee PV Solar												
24	Solar		12,725					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	12,725	25.4%	N/A	25.4%	N/A						
26	Orange Blossom PV Solar												
27	Solar		11,253					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	11,253	22.5%	N/A	22.5%	N/A						
29	Palm Bay PV Solar												
30	Solar		11,113					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	11,113	22.2%	N/A	22.2%	N/A						
32	Pea Ridge												
33	Gas		5,160				15,000	77,400	1,000,000	77,400	460,198	8.92	5.95
34	Plant Unit Info	8.0	5,160	96.0%	100.0%	96.0%	15,000			77,400	460,198	8.92	
35	PEEC												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		749,306				6,363	4,767,497	1,000,000	4,767,497	28,073,548	3.75	5.89
3	Plant Unit Info	1,283.0	749,306	86.9%	93.0%	93.5%	6,363			4,767,497	28,073,548	3.75	
4	Pelican PV Solar												
5	Solar		11,253					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	11,253	22.5%	N/A	22.5%	N/A						
7	Perdido												
8	Gas		1,896				9,900	18,770	1,000,000	18,770	94,506	4.98	5.03
9	Plant Unit Info	3.0	1,896	94.1%	100.0%	94.1%	9,900			18,770	94,506	4.98	
10	Pioneer Trail PV Solar												
11	Solar		11,948					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	11,948	23.9%	N/A	23.9%	N/A						
13	Riviera 5												
14	Gas		448,277				6,686	2,997,020	1,000,000	2,997,020	17,709,492	3.95	5.91
15	Plant Unit Info	1,326.0	448,277	50.3%	93.4%	53.8%	6,686			2,997,020	17,709,492	3.95	
16	Rodeo PV Solar												
17	Solar		11,161					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	11,161	22.3%	N/A	22.3%	N/A						
19	Sabal Palm PV Solar												
20	Solar		11,540					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	11,540	23.1%	N/A	23.1%	N/A						
22	Sanford 4												
23	Gas		61,224				7,115	435,603	1,000,000	435,603	2,569,537	4.20	5.90
24	Plant Unit Info	1,192.0	61,224	7.6%	83.4%	9.2%	7,115			435,603	2,569,537	4.20	
25	Sanford 5												
26	Gas		237,382				7,003	1,662,501	1,000,000	1,662,501	9,786,684	4.12	5.89
27	Plant Unit Info	1,192.0	237,382	29.6%	58.4%	50.8%	7,003			1,662,501	9,786,684	4.12	
28	Sawgrass PV Solar												
29	Solar		12,330					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	12,330	24.6%	N/A	24.6%	N/A						
31	Scherer 3												
32	Coal		34,543				11,561	23,492	16,999,998	399,358	1,038,127	3.01	44.19
33	Plant Unit Info	860.0	34,543	6.0%	99.6%	29.5%	11,561			399,358	1,038,127	3.01	
34	Scherer 4												
35	Coal											N/A	0.00

FLORIDA POWER & LIGHT COMPANY
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		403,308				6,848	2,761,766	1,000,000	2,761,766	16,420,652	4.07	5.95
4	Plant Unit Info	694.7	403,308	86.4%	93.9%	86.4%	6,848			2,761,766	16,420,652	4.07	
5	Smith A												
6	Plant Unit Info	40.0	0	N/A	97.8%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		14,131					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	14,131	28.2%	N/A	28.2%	N/A						
10	Space Coast												
11	Solar		1,274					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,274	19.0%	100.0%	19.0%	N/A						
13	St Lucie 1												
14	Nuclear		657,179				10,328	6,787,549	1,000,000	6,787,549	3,300,785	0.50	0.49
15	Plant Unit Info	1,003.0	657,179	97.5%	97.3%	100.0%	10,328			6,787,549	3,300,785	0.50	
16	St Lucie 2												
17	Nuclear		563,172				10,257	5,776,289	1,000,000	5,776,289	2,467,631	0.44	0.43
18	Plant Unit Info	859.6	563,172	97.5%	97.5%	100.0%	10,257			5,776,289	2,467,631	0.44	
19	Sundew PV Solar												
20	Solar		12,047					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,047	24.1%	N/A	24.1%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		11,892					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	11,892	23.8%	N/A	23.8%	N/A						
25	Sweetbay PV Solar												
26	Solar		12,117					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	12,117	24.2%	N/A	24.2%	N/A						
28	Trailside PV Solar												
29	Solar		10,325					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	10,325	20.6%	N/A	20.6%	N/A						
31	Turkey Point 3												
32	Nuclear		562,800				10,541	5,932,644	1,000,000	5,932,644	2,943,185	0.52	0.50
33	Plant Unit Info	859.0	562,800	97.5%	97.5%	100.0%	10,541			5,932,644	2,943,185	0.52	
34	Turkey Point 4												
35	Nuclear		567,437				10,456	5,933,176	1,000,000	5,933,176	3,513,627	0.62	0.59

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	866.0	567,437	97.5%	97.3%	100.0%	10,456			5,933,176	3,513,627	0.62	
2	Turkey Point 5												
3	Gas		460,368				6,921	3,186,165	1,000,000	3,186,165	18,763,511	4.08	5.89
4	Plant Unit Info	1,294.0	460,368	52.9%	93.9%	56.4%	6,921			3,186,165	18,763,511	4.08	
5	Twin Lakes ST Solar												
6	Solar		12,008					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,008	24.0%	N/A	24.0%	N/A						
8	Union Springs PV Solar												
9	Solar		10,207					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	10,207	20.4%	N/A	20.4%	N/A						
11	WCEC 01												
12	Gas		331,108				6,912	2,288,562	1,000,000	2,288,562	13,344,616	4.03	5.83
13	Plant Unit Info	1,248.0	331,108	39.5%	93.7%	42.1%	6,912			2,288,562	13,344,616	4.03	
14	WCEC 02												
15	Gas		221,959				6,785	1,505,994	1,000,000	1,505,994	8,797,541	3.96	5.84
16	Plant Unit Info	1,248.0	221,959	26.5%	43.2%	60.5%	6,785			1,505,994	8,797,541	3.96	
17	WCEC 03												
18	Gas		505,389				6,732	3,402,099	1,000,000	3,402,099	19,849,476	3.93	5.83
19	Plant Unit Info	1,254.0	505,389	60.0%	93.7%	64.0%	6,732			3,402,099	19,849,476	3.93	
20	Wildflower PV Solar												
21	Solar		13,407					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	13,407	26.8%	N/A	26.8%	N/A						
23	Willow PV Solar												
24	Solar		11,275					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	11,275	22.5%	N/A	22.5%	N/A						
26	System Totals												
27	Plant Unit Info	31,759	9,483,524				7,423			70,394,439	271,528,523	2.86	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Mar - 2022												
2	Babcock Preserve ST Solar												
3	Solar		16,622					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	16,622	30.0%	N/A	30.0%	N/A						
5	Babcock PV Solar												
6	Solar		15,355					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,355	27.7%	N/A	27.7%	N/A						
8	Barefoot PV Solar												
9	Solar		16,036					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,036	28.9%	N/A	28.9%	N/A						
11	Blue Cypress PV Solar												
12	Solar		16,632					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,632	30.0%	N/A	30.0%	N/A						
14	Blue Heron ST Solar												
15	Solar		16,622					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	16,622	30.0%	N/A	30.0%	N/A						
17	Blue Indigo PV Solar												
18	Solar		16,507					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	22.4	16,507	99.0%	N/A	99.0%	N/A						
20	Blue Springs PV Solar												
21	Solar		13,799					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	18.6	13,799	100.0%	N/A	100.0%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		16,816					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	16,816	30.3%	N/A	30.3%	N/A						
26	CCEC 3												
27	Gas		252,533				6,737	1,701,410	1,000,000	1,701,410	9,586,668	3.80	5.63
28	Plant Unit Info	1,326.0	252,533	25.6%	38.6%	66.3%	6,737			1,701,410	9,586,668	3.80	
29	Citrus PV Solar												
30	Solar		15,251					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	15,251	27.5%	N/A	27.5%	N/A						
32	Coral Farms PV Solar												
33	Solar		16,484					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	16,484	29.7%	N/A	29.7%	N/A						
35	Cotton Creek PV Solar												

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SCHEDULE: E4

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		15,141					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	20.4	15,141	100.0%	N/A	100.0%	N/A						
3	Dania Beach												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Daniel 1												
8	Coal		144,579				10,222	82,935	17,819,999	1,477,901	3,903,267	2.70	47.06
9	Plant Unit Info	502.0	144,579	38.7%	98.5%	47.6%	10,222			1,477,901	3,903,267	2.70	
10	Daniel 2												
11	Coal		153,038				10,090	86,651	17,820,001	1,544,121	4,078,161	2.66	47.06
12	Plant Unit Info	502.0	153,038	41.0%	100.0%	60.6%	10,090			1,544,121	4,078,161	2.66	
13	Desoto Solar												
14	Solar		4,460					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	4,460	24.0%	N/A	24.0%	N/A						
16	Discovery PV Solar												
17	Solar		13,011					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	13,011	23.5%	N/A	23.5%	N/A						
19	Echo River PV Solar												
20	Solar		17,543					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	17,543	31.7%	N/A	31.7%	N/A						
22	Egret PV Solar												
23	Solar		13,680					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	13,680	24.7%	N/A	24.7%	N/A						
25	Elder Branch PV Solar												
26	Solar		17,502					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	17,502	31.6%	N/A	31.6%	N/A						
28	Fort Drum PV Solar												
29	Solar		13,184					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	13,184	23.8%	N/A	23.8%	N/A						
31	Fort Myers 2												
32	Gas		804,537				7,013	5,642,355	1,000,000	5,642,355	31,811,890	3.95	5.64
33	Plant Unit Info	1,740.0	804,537	62.2%	93.8%	66.3%	7,013			5,642,355	31,811,890	3.95	
34	Fort Myers 3A												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		858				10,930	9,378	1,000,000	9,378	53,504	6.24	5.71
2	Plant Unit Info	189.0	858	0.6%	93.8%	0.7%	10,930			9,378	53,504	6.24	
3	Fort Myers 3B												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		1,227				10,742	13,181	1,000,000	13,181	74,507	6.07	5.65
6	Plant Unit Info	193.0	1,227	0.9%	93.8%	0.9%	10,742			13,181	74,507	6.07	
7	Fort Myers 3C												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		3,475				10,434	36,258	1,000,000	36,258	191,057	5.50	5.27
10	Plant Unit Info	221.0	3,475	2.1%	93.8%	2.3%	10,434			36,258	191,057	5.50	
11	Fort Myers 3D												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		1,791				11,692	20,940	1,000,000	20,940	118,338	6.61	5.65
14	Plant Unit Info	221.0	1,791	1.1%	93.8%	1.2%	11,692			20,940	118,338	6.61	
15	GCEC 4												
16	Gas		120				13,148	1,578	1,000,000	1,578	8,679	7.23	5.50
17	Plant Unit Info	78.0	120	0.2%	80.6%	0.3%	13,148			1,578	8,679	7.23	
18	GCEC 5												
19	Gas		1,080				13,147	14,204	1,000,000	14,204	78,111	7.23	5.50
20	Plant Unit Info	78.0	1,080	1.9%	70.7%	2.6%	13,147			14,204	78,111	7.23	
21	GCEC 6												
22	Gas		98,419				11,424	1,124,290	1,000,000	1,124,290	6,182,697	6.28	5.50
23	Plant Unit Info	315.0	98,419	42.0%	56.6%	74.2%	11,424			1,124,290	6,182,697	6.28	
24	GCEC 7												
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	496.0	0	N/A	95.6%	N/A	N/A						
27	GCEC 8A												
28	Gas		950				9,986	9,487	1,000,000	9,487	52,169	5.49	5.50
29	Plant Unit Info	237.5	950	0.5%	100.0%	0.5%	9,986			9,487	52,169	5.49	
30	GCEC 8B												
31	Gas		0					0	0	0	0	0.00	0.00
32	Plant Unit Info	237.5	0	N/A	100.0%	N/A	N/A						
33	GCEC 8C												
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	237.5	0	N/A	100.0%	N/A	N/A						

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		0					0	0	0	0	0.00	0.00
3	Plant Unit Info	237.5	0	N/A	100.0%	N/A	N/A						
4	Ghost Orchid PV Solar												
5	Solar		15,343					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	15,343	27.7%	N/A	27.7%	N/A						
7	Grove PV Solar												
8	Solar		14,906					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	14,906	26.9%	N/A	26.9%	N/A						
10	Hammock PV Solar												
11	Solar		17,187					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	17,187	31.0%	N/A	31.0%	N/A						
13	Hibiscus PV Solar												
14	Solar		15,687					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	15,687	28.3%	N/A	28.3%	N/A						
16	Horizon PV Solar												
17	Solar		16,542					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	16,542	29.8%	N/A	29.8%	N/A						
19	Immokalee PV Solar												
20	Solar		15,470					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	15,470	27.9%	N/A	27.9%	N/A						
22	Indian River PV Solar												
23	Solar		16,622					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	16,622	30.0%	N/A	30.0%	N/A						
25	Interstate PV Solar												
26	Solar		15,908					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	15,908	28.7%	N/A	28.7%	N/A						
28	Lakeside PV Solar												
29	Solar		14,488					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	14,488	26.1%	N/A	26.1%	N/A						
31	Lauderdale 6A												
32	Gas		2,025				10,590	21,445	1,000,000	21,445	121,872	6.02	5.68
33	Plant Unit Info	218.0	2,025	1.3%	94.0%	1.3%	10,590			21,445	121,872	6.02	
34	Lauderdale 6B												
35	Gas		2,835				10,611	30,083	1,000,000	30,083	170,935	6.03	5.68

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	218.0	2,835	1.8%	94.0%	1.9%	10,611			30,083	170,935	6.03	
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		2,025				10,590	21,445	1,000,000	21,445	116,028	5.73	5.41
5	Plant Unit Info	218.0	2,025	1.3%	94.0%	1.3%	10,590			21,445	116,028	5.73	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		2,025				10,590	21,445	1,000,000	21,445	115,829	5.72	5.40
9	Plant Unit Info	218.0	2,025	1.3%	94.0%	1.3%	10,590			21,445	115,829	5.72	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		2,025				10,590	21,445	1,000,000	21,445	115,402	5.70	5.38
13	Plant Unit Info	218.0	2,025	1.3%	94.0%	1.3%	10,590			21,445	115,402	5.70	
14	Loggerhead PV Solar												
15	Solar		16,909					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	16,909	30.5%	N/A	30.5%	N/A						
17	Magnolia PV Solar												
18	Solar		14,229					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,229	25.7%	N/A	25.7%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		582,489				6,875	4,004,460	1,000,000	4,004,460	22,384,354	3.84	5.59
30	Plant Unit Info	1,254.0	582,489	62.4%	93.9%	66.5%	6,875			4,004,460	22,384,354	3.84	
31	Manatee PV Solar												
32	Solar		15,386					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	15,386	27.8%	N/A	27.8%	N/A						
34	Martin 3												
35	Gas		33,902				8,244	279,481	1,000,000	279,481	1,535,320	4.53	5.49

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	492.0	33,902	9.3%	93.4%	9.9%	8,244			279,481	1,535,320	4.53	
2	Martin 4												
3	Gas		20,693				8,871	183,565	1,000,000	183,565	1,005,907	4.86	5.48
4	Plant Unit Info	492.0	20,693	5.7%	93.9%	6.0%	8,871			183,565	1,005,907	4.86	
5	Martin 8												
6	Gas		599,008				6,885	4,124,364	1,000,000	4,124,364	23,151,221	3.86	5.61
7	Plant Unit Info	1,258.0	599,008	64.0%	80.6%	79.4%	6,885			4,124,364	23,151,221	3.86	
8	Martin 8 Solar												
9	Solar		10,341					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	10,341	25.3%	N/A	29.0%	N/A						
11	Miami-Dade PV Solar												
12	Solar		16,199					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,199	29.2%	N/A	29.2%	N/A						
14	Nassau PV Solar												
15	Solar		13,144					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,144	23.7%	N/A	23.7%	N/A						
17	Northern Preserve ST Solar												
18	Solar		14,447					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,447	26.1%	N/A	26.1%	N/A						
20	OKEECHOBEE 1												
21	Gas		486,797				6,363	3,097,355	1,000,000	3,097,355	17,506,042	3.60	5.65
22	Plant Unit Info	1,640.0	486,797	39.9%	47.8%	83.4%	6,363			3,097,355	17,506,042	3.60	
23	Okeechobee PV Solar												
24	Solar		15,979					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	15,979	28.8%	N/A	28.8%	N/A						
26	Orange Blossom PV Solar												
27	Solar		14,288					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	14,288	25.8%	N/A	25.8%	N/A						
29	Palm Bay PV Solar												
30	Solar		14,145					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	14,145	25.5%	N/A	25.5%	N/A						
32	Pea Ridge												
33	Gas		5,712				15,000	85,680	1,000,000	85,680	487,690	8.54	5.69
34	Plant Unit Info	8.0	5,712	96.0%	100.0%	96.0%	15,000			85,680	487,690	8.54	
35	PEEC												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		842,859				6,353	5,354,355	1,000,000	5,354,355	30,200,308	3.58	5.64
3	Plant Unit Info	1,283.0	842,859	88.3%	93.0%	95.0%	6,353			5,354,355	30,200,308	3.58	
4	Pelican PV Solar												
5	Solar		14,288					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	14,288	25.8%	N/A	25.8%	N/A						
7	Perdido												
8	Gas		2,097				9,900	20,760	1,000,000	20,760	104,296	4.97	5.02
9	Plant Unit Info	3.0	2,097	94.0%	100.0%	94.0%	9,900			20,760	104,296	4.97	
10	Pioneer Trail PV Solar												
11	Solar		15,336					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	15,336	27.7%	N/A	27.7%	N/A						
13	Riviera 5												
14	Gas		390,946				6,663	2,604,874	1,000,000	2,604,874	14,662,751	3.75	5.63
15	Plant Unit Info	1,326.0	390,946	39.6%	61.2%	64.8%	6,663			2,604,874	14,662,751	3.75	
16	Rodeo PV Solar												
17	Solar		15,070					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	15,070	27.2%	N/A	27.2%	N/A						
19	Sabal Palm PV Solar												
20	Solar		14,400					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	14,400	26.0%	N/A	26.0%	N/A						
22	Sanford 4												
23	Gas		209,472				7,081	1,483,279	1,000,000	1,483,279	8,342,673	3.98	5.62
24	Plant Unit Info	1,192.0	209,472	23.6%	81.2%	29.1%	7,081			1,483,279	8,342,673	3.98	
25	Sanford 5												
26	Gas		448,072				6,939	3,109,010	1,000,000	3,109,010	17,526,088	3.91	5.64
27	Plant Unit Info	1,192.0	448,072	50.5%	94.1%	53.7%	6,939			3,109,010	17,526,088	3.91	
28	Sawgrass PV Solar												
29	Solar		15,291					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	15,291	27.6%	N/A	27.6%	N/A						
31	Scherer 3												
32	Coal		9,201				11,790	6,381	16,999,989	108,477	281,756	3.06	44.16
33	Plant Unit Info	860.0	9,201	1.4%	61.0%	2.4%	11,790			108,477	281,756	3.06	
34	Scherer 4												
35	Coal											N/A	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		462,838				6,873	3,181,270	1,000,000	3,181,270	18,107,783	3.91	5.69
4	Plant Unit Info	712.7	462,838	87.3%	93.9%	87.3%	6,873			3,181,270	18,107,783	3.91	
5	Smith A												
6	Plant Unit Info	36.0	0	N/A	98.1%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		18,494					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	18,494	33.4%	N/A	33.4%	N/A						
10	Space Coast												
11	Solar		1,626					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,626	21.9%	100.0%	21.9%	N/A						
13	St Lucie 1												
14	Nuclear		727,591				10,328	7,514,787	1,000,000	7,514,787	3,654,441	0.50	0.49
15	Plant Unit Info	1,003.0	727,591	97.5%	97.3%	100.0%	10,328			7,514,787	3,654,441	0.50	
16	St Lucie 2												
17	Nuclear		623,512				10,257	6,395,178	1,000,000	6,395,178	2,732,020	0.44	0.43
18	Plant Unit Info	859.6	623,512	97.5%	97.5%	100.0%	10,257			6,395,178	2,732,020	0.44	
19	Sundew PV Solar												
20	Solar		14,956					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	14,956	27.0%	N/A	27.0%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		15,387					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	15,387	27.8%	N/A	27.8%	N/A						
25	Sweetbay PV Solar												
26	Solar		15,004					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	15,004	27.1%	N/A	27.1%	N/A						
28	Trailside PV Solar												
29	Solar		14,636					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	14,636	26.4%	N/A	26.4%	N/A						
31	Turkey Point 3												
32	Nuclear		623,100				10,541	6,568,284	1,000,000	6,568,284	3,258,526	0.52	0.50
33	Plant Unit Info	859.0	623,100	97.5%	97.5%	100.0%	10,541			6,568,284	3,258,526	0.52	
34	Turkey Point 4												
35	Nuclear		222,922				10,456	2,330,891	1,000,000	2,330,891	1,380,353	0.62	0.59

FLORIDA POWER & LIGHT COMPANY
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SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	866.0	222,922	33.0%	34.5%	100.0%	10,456			2,330,891	1,380,353	0.62	
2	Turkey Point 5												
3	Gas		592,128				6,857	4,060,472	1,000,000	4,060,472	22,892,934	3.87	5.64
4	Plant Unit Info	1,294.0	592,128	61.5%	93.9%	65.5%	6,857			4,060,472	22,892,934	3.87	
5	Twin Lakes ST Solar												
6	Solar		16,364					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	16,364	29.5%	N/A	29.5%	N/A						
8	Union Springs PV Solar												
9	Solar		14,391					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,391	26.0%	N/A	26.0%	N/A						
11	WCEC 01												
12	Gas		500,361				6,749	3,377,000	1,000,000	3,377,000	18,882,731	3.77	5.59
13	Plant Unit Info	1,248.0	500,361	53.9%	93.7%	57.5%	6,749			3,377,000	18,882,731	3.77	
14	WCEC 02												
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	1,248.0	0	N/A	N/A	N/A	N/A						
17	WCEC 03												
18	Gas		583,055				6,721	3,918,428	1,000,000	3,918,428	21,913,047	3.76	5.59
19	Plant Unit Info	1,254.0	583,055	62.5%	93.7%	66.7%	6,721			3,918,428	21,913,047	3.76	
20	Wildflower PV Solar												
21	Solar		16,842					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	16,842	30.4%	N/A	30.4%	N/A						
23	Willow PV Solar												
24	Solar		15,261					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	15,261	27.5%	N/A	27.5%	N/A						
26	System Totals												
27	Plant Unit Info	31,785	10,199,509				7,207			73,512,937	286,789,358	2.81	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Apr - 2022												
2	Babcock Preserve ST Solar												
3	Solar		16,562					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	16,562	30.9%	N/A	30.9%	N/A						
5	Babcock PV Solar												
6	Solar		15,726					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,726	29.3%	N/A	29.3%	N/A						
8	Barefoot PV Solar												
9	Solar		16,349					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,349	30.5%	N/A	30.5%	N/A						
11	Blue Cypress PV Solar												
12	Solar		16,808					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,808	31.3%	N/A	31.3%	N/A						
14	Blue Heron ST Solar												
15	Solar		16,562					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	16,562	30.9%	N/A	30.9%	N/A						
17	Blue Indigo PV Solar												
18	Solar		17,880					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	25.1	17,880	99.0%	N/A	99.0%	N/A						
20	Blue Springs PV Solar												
21	Solar		15,288					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	21.2	15,288	100.0%	N/A	100.0%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		17,972					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	17,972	33.5%	N/A	33.5%	N/A						
26	CCEC 3												
27	Gas		353,133				6,780	2,394,229	1,000,000	2,394,229	12,110,909	3.43	5.06
28	Plant Unit Info	1,308.0	353,133	37.5%	60.1%	62.4%	6,780			2,394,229	12,110,909	3.43	
29	Citrus PV Solar												
30	Solar		15,795					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	15,795	29.5%	N/A	29.5%	N/A						
32	Coral Farms PV Solar												
33	Solar		17,330					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	17,330	32.3%	N/A	32.3%	N/A						
35	Cotton Creek PV Solar												

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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		15,828					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	22.0	15,828	100.0%	N/A	100.0%	N/A						
3	Dania Beach												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Daniel 1												
8	Coal		91,973				10,512	54,256	17,820,001	966,844	2,561,540	2.79	47.21
9	Plant Unit Info	502.0	91,973	25.5%	98.5%	44.0%	10,512			966,844	2,561,540	2.79	
10	Daniel 2												
11	Coal		106,380				10,374	61,932	17,819,999	1,103,626	2,923,928	2.75	47.21
12	Plant Unit Info	502.0	106,380	29.4%	80.0%	68.0%	10,374			1,103,626	2,923,928	2.75	
13	Desoto Solar												
14	Solar		4,930					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	4,930	27.4%	N/A	27.4%	N/A						
16	Discovery PV Solar												
17	Solar		13,744					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	13,744	25.6%	N/A	25.6%	N/A						
19	Echo River PV Solar												
20	Solar		19,341					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	19,341	36.1%	N/A	36.1%	N/A						
22	Egret PV Solar												
23	Solar		14,983					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	14,983	27.9%	N/A	27.9%	N/A						
25	Elder Branch PV Solar												
26	Solar		18,810					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	18,810	35.1%	N/A	35.1%	N/A						
28	Fort Drum PV Solar												
29	Solar		13,810					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	13,810	25.7%	N/A	25.7%	N/A						
31	Fort Myers 2												
32	Gas		767,891				7,033	5,400,249	1,000,000	5,400,249	27,316,237	3.56	5.06
33	Plant Unit Info	1,700.0	767,891	62.7%	93.8%	66.9%	7,033			5,400,249	27,316,237	3.56	
34	Fort Myers 3A												
35	Light Oil		892				11,697	1,789	5,830,012	10,431	170,056	19.07	95.05

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		450				11,697	5,267	1,000,000	5,267	26,711	5.93	5.07
2	Plant Unit Info	162.0	1,342	1.2%	93.8%	1.2%	11,697			15,698	196,768	14.66	
3	Fort Myers 3B												
4	Light Oil		614				11,463	1,208	5,830,001	7,042	114,806	18.69	95.05
5	Gas		1,984				11,463	22,739	1,000,000	22,739	116,064	5.85	5.10
6	Plant Unit Info	166.0	2,598	2.2%	93.8%	2.3%	11,463			29,781	230,870	8.89	
7	Fort Myers 3C												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		6,029				10,798	65,102	1,000,000	65,102	331,723	5.50	5.10
10	Plant Unit Info	219.0	6,029	3.8%	93.8%	4.1%	10,798			65,102	331,723	5.50	
11	Fort Myers 3D												
12	Light Oil		133				10,586	242	5,829,986	1,408	22,955	17.26	95.05
13	Gas		5,312				10,586	56,231	1,000,000	56,231	286,220	5.39	5.09
14	Plant Unit Info	219.0	5,445	3.5%	93.8%	3.7%	10,586			57,639	309,174	5.68	
15	GCEC 4												
16	Gas		20,247				13,147	266,195	1,000,000	266,195	1,309,210	6.47	4.92
17	Plant Unit Info	78.0	20,247	36.1%	93.3%	38.6%	13,147			266,195	1,309,210	6.47	
18	GCEC 5												
19	Gas		19,287				13,147	253,569	1,000,000	253,569	1,247,113	6.47	4.92
20	Plant Unit Info	78.0	19,287	34.3%	86.3%	39.8%	13,147			253,569	1,247,113	6.47	
21	GCEC 6												
22	Gas		95,199				11,424	1,087,507	1,000,000	1,087,507	5,348,615	5.62	4.92
23	Plant Unit Info	315.0	95,199	42.0%	94.9%	44.2%	11,424			1,087,507	5,348,615	5.62	
24	GCEC 7												
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	496.0	0	N/A	98.8%	N/A	N/A						
27	GCEC 8A												
28	Gas		9,792				9,986	97,788	1,000,000	97,788	480,942	4.91	4.92
29	Plant Unit Info	237.5	9,792	5.7%	100.0%	5.7%	9,986			97,788	480,942	4.91	
30	GCEC 8B												
31	Gas		7,086				9,986	70,765	1,000,000	70,765	348,041	4.91	4.92
32	Plant Unit Info	237.5	7,086	4.1%	100.0%	4.1%	9,986			70,765	348,041	4.91	
33	GCEC 8C												
34	Gas		4,224				9,986	42,181	1,000,000	42,181	207,458	4.91	4.92
35	Plant Unit Info	237.5	4,224	2.5%	100.0%	2.5%	9,986			42,181	207,458	4.91	

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ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		2,800				9,986	27,960	1,000,000	27,960	137,513	4.91	4.92
3	Plant Unit Info	237.5	2,800	1.6%	100.0%	1.6%	9,986			27,960	137,513	4.91	
4	Ghost Orchid PV Solar												
5	Solar		15,525					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	15,525	28.9%	N/A	28.9%	N/A						
7	Grove PV Solar												
8	Solar		15,255					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	15,255	28.4%	N/A	28.4%	N/A						
10	Hammock PV Solar												
11	Solar		17,146					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	17,146	32.0%	N/A	32.0%	N/A						
13	Hibiscus PV Solar												
14	Solar		16,258					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	16,258	30.3%	N/A	30.3%	N/A						
16	Horizon PV Solar												
17	Solar		17,428					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	17,428	32.5%	N/A	32.5%	N/A						
19	Immokalee PV Solar												
20	Solar		15,669					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	15,669	29.2%	N/A	29.2%	N/A						
22	Indian River PV Solar												
23	Solar		16,798					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	16,798	31.3%	N/A	31.3%	N/A						
25	Interstate PV Solar												
26	Solar		16,464					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	16,464	30.7%	N/A	30.7%	N/A						
28	Lakeside PV Solar												
29	Solar		14,942					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	14,942	27.9%	N/A	27.9%	N/A						
31	Lauderdale 6A												
32	Gas		4,102				10,600	43,480	1,000,000	43,480	221,701	5.40	5.10
33	Plant Unit Info	216.0	4,102	2.6%	94.0%	2.8%	10,600			43,480	221,701	5.40	
34	Lauderdale 6B												
35	Gas		3,811				10,503	40,026	1,000,000	40,026	204,241	5.36	5.10

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	216.0	3,811	2.5%	94.0%	2.6%	10,503			40,026	204,241	5.36	
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		3,500				10,658	37,302	1,000,000	37,302	189,551	5.42	5.08
5	Plant Unit Info	216.0	3,500	2.3%	94.0%	2.4%	10,658			37,302	189,551	5.42	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		3,593				10,454	37,562	1,000,000	37,562	191,476	5.33	5.10
9	Plant Unit Info	216.0	3,593	2.3%	94.0%	2.5%	10,454			37,562	191,476	5.33	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		1,805				10,434	18,834	1,000,000	18,834	96,067	5.32	5.10
13	Plant Unit Info	216.0	1,805	1.2%	94.0%	1.2%	10,434			18,834	96,067	5.32	
14	Loggerhead PV Solar												
15	Solar		16,886					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	16,886	31.5%	N/A	31.5%	N/A						
17	Magnolia PV Solar												
18	Solar		15,745					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	15,745	29.4%	N/A	29.4%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		121,904				6,753	823,174	1,000,000	823,174	4,071,275	3.34	4.95
30	Plant Unit Info	1,223.0	121,904	8.9%	8.9%	100.0%	6,753			823,174	4,071,275	3.34	
31	Manatee PV Solar												
32	Solar		15,985					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	15,985	29.8%	N/A	29.8%	N/A						
34	Martin 3												
35	Gas		183,491				7,347	1,348,068	1,000,000	1,348,068	6,664,104	3.63	4.94

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	464.0	183,491	54.9%	93.4%	58.5%	7,347			1,348,068	6,664,104	3.63	
2	Martin 4												
3	Gas		38,514				7,890	303,890	1,000,000	303,890	1,502,986	3.90	4.95
4	Plant Unit Info	464.0	38,514	11.5%	77.2%	14.9%	7,890			303,890	1,502,986	3.90	
5	Martin 8												
6	Gas		499,290				6,910	3,450,336	1,000,000	3,450,336	17,055,130	3.42	4.94
7	Plant Unit Info	1,218.0	499,290	56.9%	73.5%	77.5%	6,910			3,450,336	17,055,130	3.42	
8	Martin 8 Solar												
9	Solar		11,448					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	11,448	28.9%	N/A	36.1%	N/A						
11	Miami-Dade PV Solar												
12	Solar		16,134					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,134	30.1%	N/A	30.1%	N/A						
14	Nassau PV Solar												
15	Solar		14,508					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,508	27.1%	N/A	27.1%	N/A						
17	Northern Preserve ST Solar												
18	Solar		14,395					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,395	26.8%	N/A	26.8%	N/A						
20	OKEECHOBEE 1												
21	Gas		932,560				6,311	5,885,141	1,000,000	5,885,141	29,785,909	3.19	5.06
22	Plant Unit Info	1,603.0	932,560	80.8%	93.0%	86.9%	6,311			5,885,141	29,785,909	3.19	
23	Okeechobee PV Solar												
24	Solar		16,780					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	16,780	31.3%	N/A	31.3%	N/A						
26	Orange Blossom PV Solar												
27	Solar		14,665					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	14,665	27.3%	N/A	27.3%	N/A						
29	Palm Bay PV Solar												
30	Solar		14,558					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	14,558	27.1%	N/A	27.1%	N/A						
32	Pea Ridge												
33	Gas		5,528				15,000	82,920	1,000,000	82,920	423,209	7.66	5.10
34	Plant Unit Info	8.0	5,528	96.0%	100.0%	96.0%	15,000			82,920	423,209	7.66	
35	PEEC												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		791,241				6,365	5,036,002	1,000,000	5,036,002	25,469,246	3.22	5.06
3	Plant Unit Info	1,254.0	791,241	87.6%	93.0%	94.3%	6,365			5,036,002	25,469,246	3.22	
4	Pelican PV Solar												
5	Solar		14,665					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	14,665	27.3%	N/A	27.3%	N/A						
7	Perdido												
8	Gas		2,031				9,900	20,107	1,000,000	20,107	100,573	4.95	5.00
9	Plant Unit Info	3.0	2,031	94.0%	100.0%	94.0%	9,900			20,107	100,573	4.95	
10	Pioneer Trail PV Solar												
11	Solar		16,141					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	16,141	30.1%	N/A	30.1%	N/A						
13	Riviera 5												
14	Gas		544,317				6,684	3,638,336	1,000,000	3,638,336	18,413,356	3.38	5.06
15	Plant Unit Info	1,308.0	544,317	57.8%	93.4%	61.9%	6,684			3,638,336	18,413,356	3.38	
16	Rodeo PV Solar												
17	Solar		16,443					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	16,443	30.7%	N/A	30.7%	N/A						
19	Sabal Palm PV Solar												
20	Solar		14,879					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	14,879	27.7%	N/A	27.7%	N/A						
22	Sanford 4												
23	Gas		193,541				7,223	1,397,853	1,000,000	1,397,853	7,085,590	3.66	5.07
24	Plant Unit Info	1,147.0	193,541	23.4%	94.1%	24.9%	7,223			1,397,853	7,085,590	3.66	
25	Sanford 5												
26	Gas		450,011				7,022	3,159,917	1,000,000	3,159,917	15,983,936	3.55	5.06
27	Plant Unit Info	1,147.0	450,011	54.5%	94.1%	57.9%	7,022			3,159,917	15,983,936	3.55	
28	Sawgrass PV Solar												
29	Solar		15,469					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	15,469	28.8%	N/A	28.8%	N/A						
31	Scherer 3												
32	Coal											N/A	0.00
33	Plant Unit Info	860.0	0	N/A	93.1%	N/A	N/A						
34	Scherer 4												
35	Coal											N/A	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		315,134				6,883	2,169,172	1,000,000	2,169,172	11,071,057	3.51	5.10
4	Plant Unit Info	712.7	315,134	61.4%	93.9%	97.5%	6,883			2,169,172	11,071,057	3.51	
5	Smith A												
6	Plant Unit Info	36.0	0	N/A	98.5%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		19,947					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	19,947	37.2%	N/A	37.2%	N/A						
10	Space Coast												
11	Solar		1,682					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,682	23.4%	100.0%	23.4%	N/A						
13	St Lucie 1												
14	Nuclear		688,631				10,560	7,271,879	1,000,000	7,271,879	3,536,315	0.51	0.49
15	Plant Unit Info	981.0	688,631	97.5%	97.3%	100.0%	10,560			7,271,879	3,536,315	0.51	
16	St Lucie 2												
17	Nuclear		589,637				10,496	6,188,655	1,000,000	6,188,655	2,643,793	0.45	0.43
18	Plant Unit Info	840.0	589,637	97.5%	97.5%	100.0%	10,496			6,188,655	2,643,793	0.45	
19	Sundew PV Solar												
20	Solar		15,278					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	15,278	28.5%	N/A	28.5%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		16,228					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	16,228	30.3%	N/A	30.3%	N/A						
25	Sweetbay PV Solar												
26	Solar		14,791					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	14,791	27.6%	N/A	27.6%	N/A						
28	Trailside PV Solar												
29	Solar		16,246					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	16,246	30.3%	N/A	30.3%	N/A						
31	Turkey Point 3												
32	Nuclear		587,592				10,818	6,356,806	1,000,000	6,356,806	3,153,611	0.54	0.50
33	Plant Unit Info	837.0	587,592	97.5%	97.5%	100.0%	10,818			6,356,806	3,153,611	0.54	
34	Turkey Point 4												
35	Nuclear		414,742				10,729	4,449,638	1,000,000	4,449,638	2,348,074	0.57	0.53

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	844.0	414,742	67.5%	68.1%	100.0%	10,729			4,449,638	2,348,074	0.57	
2	Turkey Point 5												
3	Gas		427,175				6,996	2,988,463	1,000,000	2,988,463	15,127,933	3.54	5.06
4	Plant Unit Info	1,256.0	427,175	47.2%	93.9%	50.3%	6,996			2,988,463	15,127,933	3.54	
5	Twin Lakes ST Solar												
6	Solar		17,489					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	17,489	32.6%	N/A	32.6%	N/A						
8	Union Springs PV Solar												
9	Solar		15,925					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,925	29.7%	N/A	29.7%	N/A						
11	WCEC 01												
12	Gas		587,042				6,736	3,954,102	1,000,000	3,954,102	19,547,067	3.33	4.94
13	Plant Unit Info	1,223.0	587,042	66.7%	93.7%	71.1%	6,736			3,954,102	19,547,067	3.33	
14	WCEC 02												
15	Gas		68,965				6,924	477,533	1,000,000	477,533	2,355,700	3.42	4.93
16	Plant Unit Info	1,223.0	68,965	4.8%	4.3%	100.0%	6,924			477,533	2,355,700	3.42	
17	WCEC 03												
18	Gas		645,741				6,697	4,324,504	1,000,000	4,324,504	21,379,134	3.31	4.94
19	Plant Unit Info	1,228.0	645,741	73.0%	93.7%	77.9%	6,697			4,324,504	21,379,134	3.31	
20	Wildflower PV Solar												
21	Solar		17,225					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	17,225	32.1%	N/A	32.1%	N/A						
23	Willow PV Solar												
24	Solar		16,235					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	16,235	30.3%	N/A	30.3%	N/A						
26	System Totals												
27	Plant Unit Info	31,165	10,390,275				7,255			75,382,833	263,681,074	2.54	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	May - 2022												
2	Babcock Preserve ST Solar												
3	Solar		17,144					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	17,144	30.9%	N/A	30.9%	N/A						
5	Babcock PV Solar												
6	Solar		16,053					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	16,053	29.0%	N/A	29.0%	N/A						
8	Barefoot PV Solar												
9	Solar		16,854					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,854	30.4%	N/A	30.4%	N/A						
11	Blue Cypress PV Solar												
12	Solar		17,300					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	17,300	31.2%	N/A	31.2%	N/A						
14	Blue Heron ST Solar												
15	Solar		17,144					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	17,144	30.9%	N/A	30.9%	N/A						
17	Blue Indigo PV Solar												
18	Solar		20,367					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	27.7	20,367	99.0%	N/A	99.0%	N/A						
20	Blue Springs PV Solar												
21	Solar		16,896					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	22.7	16,896	100.0%	N/A	100.0%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		19,198					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	19,198	34.6%	N/A	34.6%	N/A						
26	CCEC 3												
27	Gas		369,112				6,780	2,502,726	1,000,000	2,502,726	12,041,664	3.26	4.81
28	Plant Unit Info	1,308.0	369,112	37.9%	66.6%	57.0%	6,780			2,502,726	12,041,664	3.26	
29	Citrus PV Solar												
30	Solar		16,286					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	16,286	29.4%	N/A	29.4%	N/A						
32	Coral Farms PV Solar												
33	Solar		18,438					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	18,438	33.3%	N/A	33.3%	N/A						
35	Cotton Creek PV Solar												

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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		17,466					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	23.5	17,466	100.0%	N/A	100.0%	N/A						
3	Dania Beach												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Daniel 1												
8	Coal		94,585				10,744	57,027	17,820,001	1,016,221	2,689,579	2.84	47.16
9	Plant Unit Info	502.0	94,585	25.3%	98.5%	47.4%	10,744			1,016,221	2,689,579	2.84	
10	Daniel 2												
11	Coal		106,626				10,612	63,495	17,819,999	1,131,481	2,994,633	2.81	47.16
12	Plant Unit Info	502.0	106,626	28.6%	41.8%	53.8%	10,612			1,131,481	2,994,633	2.81	
13	Desoto Solar												
14	Solar		5,080					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	5,080	27.3%	N/A	27.3%	N/A						
16	Discovery PV Solar												
17	Solar		14,522					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	14,522	26.2%	N/A	26.2%	N/A						
19	Echo River PV Solar												
20	Solar		21,384					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	21,384	38.6%	N/A	38.6%	N/A						
22	Egret PV Solar												
23	Solar		16,548					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	16,548	29.9%	N/A	29.9%	N/A						
25	Elder Branch PV Solar												
26	Solar		20,244					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	20,244	36.5%	N/A	36.5%	N/A						
28	Fort Drum PV Solar												
29	Solar		14,041					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	14,041	25.3%	N/A	25.3%	N/A						
31	Fort Myers 2												
32	Gas		745,822				7,024	5,238,918	1,000,000	5,238,918	25,189,607	3.38	4.81
33	Plant Unit Info	1,700.0	745,822	59.0%	93.8%	62.9%	7,024			5,238,918	25,189,607	3.38	
34	Fort Myers 3A												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		419				14,076	5,898	1,000,000	5,898	28,273	6.75	4.79
2	Plant Unit Info	162.0	419	0.4%	93.8%	0.4%	14,076			5,898	28,273	6.75	
3	Fort Myers 3B												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		764				11,381	8,695	1,000,000	8,695	41,971	5.49	4.83
6	Plant Unit Info	166.0	764	0.6%	93.8%	0.7%	11,381			8,695	41,971	5.49	
7	Fort Myers 3C												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		1,418				10,442	14,807	1,000,000	14,807	71,788	5.06	4.85
10	Plant Unit Info	219.0	1,418	0.9%	93.8%	0.9%	10,442			14,807	71,788	5.06	
11	Fort Myers 3D												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		2,228				10,501	23,397	1,000,000	23,397	112,962	5.07	4.83
14	Plant Unit Info	219.0	2,228	1.4%	93.8%	1.5%	10,501			23,397	112,962	5.07	
15	GCEC 4												
16	Gas		19,207				13,147	252,517	1,000,000	252,517	1,182,512	6.16	4.68
17	Plant Unit Info	78.0	19,207	33.1%	97.3%	56.9%	13,147			252,517	1,182,512	6.16	
18	GCEC 5												
19	Gas		5,762				13,147	75,755	1,000,000	75,755	354,753	6.16	4.68
20	Plant Unit Info	78.0	5,762	9.9%	99.9%	66.7%	13,147			75,755	354,753	6.16	
21	GCEC 6												
22	Gas		98,419				11,424	1,124,290	1,000,000	1,124,290	5,264,938	5.35	4.68
23	Plant Unit Info	315.0	98,419	42.0%	98.5%	52.3%	11,424			1,124,290	5,264,938	5.35	
24	GCEC 7												
25	Gas		1,800				11,772	21,189	1,000,000	21,189	99,228	5.51	4.68
26	Plant Unit Info	496.0	1,800	0.5%	60.1%	69.4%	11,772			21,189	99,228	5.51	
27	GCEC 8A												
28	Gas		19,879				9,986	198,515	1,000,000	198,515	929,625	4.68	4.68
29	Plant Unit Info	234.5	19,879	11.4%	100.0%	11.4%	9,986			198,515	929,625	4.68	
30	GCEC 8B												
31	Gas		18,806				9,986	187,798	1,000,000	187,798	879,437	4.68	4.68
32	Plant Unit Info	234.5	18,806	10.8%	100.0%	10.8%	9,986			187,798	879,437	4.68	
33	GCEC 8C												
34	Gas		17,685				9,986	176,605	1,000,000	176,605	827,024	4.68	4.68
35	Plant Unit Info	234.5	17,685	10.1%	100.0%	10.1%	9,986			176,605	827,024	4.68	

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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		12,759				9,986	127,414	1,000,000	127,414	596,666	4.68	4.68
3	Plant Unit Info	234.5	12,759	7.3%	100.0%	7.3%	9,986			127,414	596,666	4.68	
4	Ghost Orchid PV Solar												
5	Solar		15,592					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	15,592	28.1%	N/A	28.1%	N/A						
7	Grove PV Solar												
8	Solar		15,629					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	15,629	28.2%	N/A	28.2%	N/A						
10	Hammock PV Solar												
11	Solar		17,551					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	17,551	31.7%	N/A	31.7%	N/A						
13	Hibiscus PV Solar												
14	Solar		17,041					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	17,041	30.8%	N/A	30.8%	N/A						
16	Horizon PV Solar												
17	Solar		18,629					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	18,629	33.6%	N/A	33.6%	N/A						
19	Immokalee PV Solar												
20	Solar		15,743					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	15,743	28.4%	N/A	28.4%	N/A						
22	Indian River PV Solar												
23	Solar		17,289					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	17,289	31.2%	N/A	31.2%	N/A						
25	Interstate PV Solar												
26	Solar		16,892					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	16,892	30.5%	N/A	30.5%	N/A						
28	Lakeside PV Solar												
29	Solar		15,468					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	15,468	27.9%	N/A	27.9%	N/A						
31	Lauderdale 6A												
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
34	Lauderdale 6B												
35	Gas		3,026				10,820	32,742	1,000,000	32,742	158,085	5.22	4.83

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	216.0	3,026	1.9%	94.0%	2.0%	10,820			32,742	158,085	5.22	
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		1,003				10,564	10,596	1,000,000	10,596	50,792	5.06	4.79
5	Plant Unit Info	216.0	1,003	0.6%	94.0%	0.7%	10,564			10,596	50,792	5.06	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		1,404				10,481	14,715	1,000,000	14,715	71,342	5.08	4.85
9	Plant Unit Info	216.0	1,404	0.9%	94.0%	0.9%	10,481			14,715	71,342	5.08	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
14	Loggerhead PV Solar												
15	Solar		17,304					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	17,304	31.2%	N/A	31.2%	N/A						
17	Magnolia PV Solar												
18	Solar		17,153					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	17,153	31.0%	N/A	31.0%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		529,248				6,843	3,621,420	1,000,000	3,621,420	17,025,033	3.22	4.70
30	Plant Unit Info	1,235.0	529,248	57.2%	71.3%	80.2%	6,843			3,621,420	17,025,033	3.22	
31	Manatee PV Solar												
32	Solar		16,600					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	16,600	30.0%	N/A	30.0%	N/A						
34	Martin 3												
35	Gas		160,661				7,332	1,177,958	1,000,000	1,177,958	5,548,181	3.45	4.71

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	464.0	160,661	46.5%	93.4%	49.6%	7,332			1,177,958	5,548,181	3.45	
2	Martin 4												
3	Gas		136,764				7,394	1,011,180	1,000,000	1,011,180	4,762,330	3.48	4.71
4	Plant Unit Info	464.0	136,764	39.6%	77.8%	50.9%	7,394			1,011,180	4,762,330	3.48	
5	Martin 8												
6	Gas		623,363				6,929	4,319,251	1,000,000	4,319,251	20,315,874	3.26	4.70
7	Plant Unit Info	1,218.0	623,363	68.8%	93.5%	73.6%	6,929			4,319,251	20,315,874	3.26	
8	Martin 8 Solar												
9	Solar		14,074					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	14,074	34.4%	N/A	34.4%	N/A						
11	Miami-Dade PV Solar												
12	Solar		16,355					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,355	29.5%	N/A	29.5%	N/A						
14	Nassau PV Solar												
15	Solar		16,020					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	16,020	28.9%	N/A	28.9%	N/A						
17	Northern Preserve ST Solar												
18	Solar		14,901					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,901	26.9%	N/A	26.9%	N/A						
20	OKEECHOBEE 1												
21	Gas		874,377				6,349	5,551,262	1,000,000	5,551,262	26,862,120	3.07	4.84
22	Plant Unit Info	1,603.0	874,377	73.3%	93.0%	78.8%	6,349			5,551,262	26,862,120	3.07	
23	Okeechobee PV Solar												
24	Solar		17,667					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	17,667	31.9%	N/A	31.9%	N/A						
26	Orange Blossom PV Solar												
27	Solar		15,304					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	15,304	27.6%	N/A	27.6%	N/A						
29	Palm Bay PV Solar												
30	Solar		15,233					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	15,233	27.5%	N/A	27.5%	N/A						
32	Pea Ridge												
33	Gas		5,712				15,000	85,680	1,000,000	85,680	417,044	7.30	4.87
34	Plant Unit Info	8.0	5,712	96.0%	100.0%	96.0%	15,000			85,680	417,044	7.30	
35	PEEC												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		762,128				6,407	4,883,324	1,000,000	4,883,324	23,481,770	3.08	4.81
3	Plant Unit Info	1,254.0	762,128	81.7%	93.0%	87.9%	6,407			4,883,324	23,481,770	3.08	
4	Pelican PV Solar												
5	Solar		15,304					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	15,304	27.6%	N/A	27.6%	N/A						
7	Perdido												
8	Gas		2,097				9,900	20,760	1,000,000	20,760	100,592	4.80	4.85
9	Plant Unit Info	3.0	2,097	94.0%	100.0%	94.0%	9,900			20,760	100,592	4.80	
10	Pioneer Trail PV Solar												
11	Solar		16,868					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	16,868	30.4%	N/A	30.4%	N/A						
13	Riviera 5												
14	Gas		570,376				6,683	3,812,030	1,000,000	3,812,030	18,439,189	3.23	4.84
15	Plant Unit Info	1,308.0	570,376	58.6%	93.4%	62.7%	6,683			3,812,030	18,439,189	3.23	
16	Rodeo PV Solar												
17	Solar		17,336					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	17,336	31.3%	N/A	31.3%	N/A						
19	Sabal Palm PV Solar												
20	Solar		15,192					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	15,192	27.4%	N/A	27.4%	N/A						
22	Sanford 4												
23	Gas		420,604				7,030	2,956,887	1,000,000	2,956,887	14,220,105	3.38	4.81
24	Plant Unit Info	1,147.0	420,604	49.3%	94.1%	52.4%	7,030			2,956,887	14,220,105	3.38	
25	Sanford 5												
26	Gas		423,490				7,039	2,980,926	1,000,000	2,980,926	14,335,504	3.39	4.81
27	Plant Unit Info	1,147.0	423,490	49.6%	94.1%	52.8%	7,039			2,980,926	14,335,504	3.39	
28	Sawgrass PV Solar												
29	Solar		15,472					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	15,472	27.9%	N/A	27.9%	N/A						
31	Scherer 3												
32	Coal		7,958				11,463	5,366	17,000,009	91,223	236,343	2.97	44.04
33	Plant Unit Info	860.0	7,958	1.2%	99.6%	33.4%	11,463			91,223	236,343	2.97	
34	Scherer 4												
35	Coal											N/A	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		462,181				6,884	3,181,721	1,000,000	3,181,721	15,486,918	3.35	4.87
4	Plant Unit Info	712.7	462,181	87.2%	93.9%	96.9%	6,884			3,181,721	15,486,918	3.35	
5	Smith A												
6	Plant Unit Info	36.0	0	N/A	98.4%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		21,623					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	21,623	39.0%	N/A	39.0%	N/A						
10	Space Coast												
11	Solar		1,690					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,690	22.7%	100.0%	22.7%	N/A						
13	St Lucie 1												
14	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,654,191	0.51	0.49
15	Plant Unit Info	981.0	711,586	97.5%	97.3%	100.0%	10,560			7,514,275	3,654,191	0.51	
16	St Lucie 2												
17	Nuclear		609,292				10,496	6,394,944	1,000,000	6,394,944	2,731,920	0.45	0.43
18	Plant Unit Info	840.0	609,292	97.5%	97.5%	100.0%	10,496			6,394,944	2,731,920	0.45	
19	Sundew PV Solar												
20	Solar		15,426					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	15,426	27.8%	N/A	27.8%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		17,595					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	17,595	31.7%	N/A	31.7%	N/A						
25	Sweetbay PV Solar												
26	Solar		15,082					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	15,082	27.2%	N/A	27.2%	N/A						
28	Trailside PV Solar												
29	Solar		17,375					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	17,375	31.4%	N/A	31.4%	N/A						
31	Turkey Point 3												
32	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,258,732	0.54	0.50
33	Plant Unit Info	837.0	607,178	97.5%	97.5%	100.0%	10,818			6,568,699	3,258,732	0.54	
34	Turkey Point 4												
35	Nuclear		612,238				10,729	6,568,514	1,000,000	6,568,514	3,466,205	0.57	0.53

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	844.0	612,238	97.5%	97.3%	100.0%	10,729			6,568,514	3,466,205	0.57	
2	Turkey Point 5												
3	Gas		352,963				6,997	2,469,786	1,000,000	2,469,786	11,889,545	3.37	4.81
4	Plant Unit Info	1,256.0	352,963	37.8%	93.9%	40.2%	6,997			2,469,786	11,889,545	3.37	
5	Twin Lakes ST Solar												
6	Solar		18,682					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	18,682	33.7%	N/A	33.7%	N/A						
8	Union Springs PV Solar												
9	Solar		17,350					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	17,350	31.3%	N/A	31.3%	N/A						
11	WCEC 01												
12	Gas		481,124				6,773	3,258,769	1,000,000	3,258,769	15,320,297	3.18	4.70
13	Plant Unit Info	1,223.0	481,124	52.9%	93.7%	56.4%	6,773			3,258,769	15,320,297	3.18	
14	WCEC 02												
15	Gas		420,399				6,774	2,847,950	1,000,000	2,847,950	13,388,328	3.18	4.70
16	Plant Unit Info	1,223.0	420,399	46.2%	59.8%	76.5%	6,774			2,847,950	13,388,328	3.18	
17	WCEC 03												
18	Gas		622,054				6,734	4,189,109	1,000,000	4,189,109	19,693,400	3.17	4.70
19	Plant Unit Info	1,228.0	622,054	68.1%	93.7%	72.7%	6,734			4,189,109	19,693,400	3.17	
20	Wildflower PV Solar												
21	Solar		17,745					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	17,745	32.0%	N/A	32.0%	N/A						
23	Willow PV Solar												
24	Solar		17,317					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	17,317	31.2%	N/A	31.2%	N/A						
26	System Totals												
27	Plant Unit Info	31,171	11,751,984				7,290			85,669,947	288,218,501	2.45	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Jun - 2022												
2	Babcock Preserve ST Solar												
3	Solar		14,140					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,140	26.4%	N/A	26.4%	N/A						
5	Babcock PV Solar												
6	Solar		13,902					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,902	25.9%	N/A	25.9%	N/A						
8	Barefoot PV Solar												
9	Solar		14,269					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,269	26.6%	N/A	26.6%	N/A						
11	Blue Cypress PV Solar												
12	Solar		14,777					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,777	27.6%	N/A	27.6%	N/A						
14	Blue Heron ST Solar												
15	Solar		14,140					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,140	26.4%	N/A	26.4%	N/A						
17	Blue Indigo PV Solar												
18	Solar		18,763					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	26.3	18,763	99.0%	N/A	99.0%	N/A						
20	Blue Springs PV Solar												
21	Solar		14,979					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	20.8	14,979	100.0%	N/A	100.0%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		15,362					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	15,362	28.6%	N/A	28.6%	N/A						
26	CCEC 3												
27	Gas		426,866				6,737	2,875,723	1,000,000	2,875,723	13,424,258	3.14	4.67
28	Plant Unit Info	1,308.0	426,866	45.3%	93.4%	48.5%	6,737			2,875,723	13,424,258	3.14	
29	Citrus PV Solar												
30	Solar		14,087					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	14,087	26.3%	N/A	26.3%	N/A						
32	Coral Farms PV Solar												
33	Solar		16,007					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	16,007	29.8%	N/A	29.8%	N/A						
35	Cotton Creek PV Solar												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		15,880					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	22.1	15,880	100.0%	N/A	100.0%	N/A						
3	Dania Beach												
4	Light Oil		6,149				6,165	6,503	5,830,003	37,910	516,066	8.39	79.36
5	Gas		652,297				6,165	4,021,568	1,000,000	4,021,568	18,416,883	2.82	4.58
6	Plant Unit Info	1,182.0	658,446	77.4%	94.5%	85.5%	6,165			4,059,478	18,932,949	2.88	
7	Daniel 1												
8	Coal		125,127				10,450	73,379	17,819,999	1,307,610	3,456,142	2.76	47.10
9	Plant Unit Info	502.0	125,127	34.6%	98.5%	57.2%	10,450			1,307,610	3,456,142	2.76	
10	Daniel 2												
11	Coal		131,645				10,324	76,271	17,820,001	1,359,153	3,592,374	2.73	47.10
12	Plant Unit Info	502.0	131,645	36.4%	100.0%	69.2%	10,324			1,359,153	3,592,374	2.73	
13	Desoto Solar												
14	Solar		4,355					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	4,355	24.2%	N/A	24.2%	N/A						
16	Discovery PV Solar												
17	Solar		11,909					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	11,909	22.2%	N/A	22.2%	N/A						
19	Echo River PV Solar												
20	Solar		19,127					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	19,127	35.7%	N/A	35.7%	N/A						
22	Egret PV Solar												
23	Solar		13,779					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	13,779	25.7%	N/A	25.7%	N/A						
25	Elder Branch PV Solar												
26	Solar		17,362					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	17,362	32.4%	N/A	32.4%	N/A						
28	Fort Drum PV Solar												
29	Solar		12,014					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	12,014	22.4%	N/A	22.4%	N/A						
31	Fort Myers 2												
32	Gas		745,789				7,027	5,240,692	1,000,000	5,240,692	24,469,072	3.28	4.67
33	Plant Unit Info	1,700.0	745,789	60.9%	93.8%	65.0%	7,027			5,240,692	24,469,072	3.28	
34	Fort Myers 3A												
35	Light Oil		108				11,547	213	5,829,933	1,243	20,265	18.82	95.05

FLORIDA POWER & LIGHT COMPANY
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		1,383				11,547	15,973	1,000,000	15,973	74,972	5.42	4.69
2	Plant Unit Info	162.0	1,491	1.3%	93.8%	1.4%	11,547			17,216	95,237	6.39	
3	Fort Myers 3B												
4	Light Oil		60				11,478	119	5,829,823	692	11,282	18.71	95.04
5	Gas		2,199				11,478	25,236	1,000,000	25,236	118,528	5.39	4.70
6	Plant Unit Info	166.0	2,259	1.9%	93.8%	2.0%	11,478			25,928	129,809	5.75	
7	Fort Myers 3C												
8	Light Oil		136				10,687	250	5,830,099	1,457	23,753	17.42	95.05
9	Gas		10,147				10,687	108,440	1,000,000	108,440	506,127	4.99	4.67
10	Plant Unit Info	219.0	10,283	6.5%	93.8%	7.0%	10,687			109,897	529,881	5.15	
11	Fort Myers 3D												
12	Light Oil		279				10,712	513	5,829,972	2,992	48,778	17.46	95.05
13	Gas		10,395				10,712	111,344	1,000,000	111,344	519,537	5.00	4.67
14	Plant Unit Info	219.0	10,674	6.8%	93.8%	7.2%	10,712			114,336	568,316	5.32	
15	GCEC 4												
16	Gas		12,764				13,147	167,819	1,000,000	167,819	749,495	5.87	4.47
17	Plant Unit Info	78.0	12,764	22.7%	97.2%	57.5%	13,147			167,819	749,495	5.87	
18	GCEC 5												
19	Gas		16,046				13,147	210,957	1,000,000	210,957	942,156	5.87	4.47
20	Plant Unit Info	78.0	16,046	28.6%	99.9%	66.4%	13,147			210,957	942,156	5.87	
21	GCEC 6												
22	Gas		97,546				11,419	1,113,863	1,000,000	1,113,863	4,974,629	5.10	4.47
23	Plant Unit Info	315.0	97,546	43.0%	98.5%	63.6%	11,419			1,113,863	4,974,629	5.10	
24	GCEC 7												
25	Gas		128,174				11,679	1,496,913	1,000,000	1,496,913	6,685,370	5.22	4.47
26	Plant Unit Info	496.0	128,174	35.9%	98.8%	68.1%	11,679			1,496,913	6,685,370	5.22	
27	GCEC 8A												
28	Gas		51,041				9,986	509,699	1,000,000	509,699	2,276,371	4.46	4.47
29	Plant Unit Info	234.5	51,041	30.2%	100.0%	30.2%	9,986			509,699	2,276,371	4.46	
30	GCEC 8B												
31	Gas		45,184				9,986	451,212	1,000,000	451,212	2,015,160	4.46	4.47
32	Plant Unit Info	234.5	45,184	26.8%	100.0%	26.8%	9,986			451,212	2,015,160	4.46	
33	GCEC 8C												
34	Gas		44,082				9,986	440,200	1,000,000	440,200	1,965,978	4.46	4.47
35	Plant Unit Info	234.5	44,082	26.1%	100.0%	26.1%	9,986			440,200	1,965,978	4.46	

FLORIDA POWER & LIGHT COMPANY
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SCHEDULE: E4

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		38,868				9,986	388,135	1,000,000	388,135	1,733,453	4.46	4.47
3	Plant Unit Info	234.5	38,868	23.0%	100.0%	23.0%	9,986			388,135	1,733,453	4.46	
4	Ghost Orchid PV Solar												
5	Solar		13,220					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	13,220	24.7%	N/A	24.7%	N/A						
7	Grove PV Solar												
8	Solar		13,506					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	13,506	25.2%	N/A	25.2%	N/A						
10	Hammock PV Solar												
11	Solar		14,497					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	14,497	27.0%	N/A	27.0%	N/A						
13	Hibiscus PV Solar												
14	Solar		14,985					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	14,985	27.9%	N/A	27.9%	N/A						
16	Horizon PV Solar												
17	Solar		16,044					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	16,044	29.9%	N/A	29.9%	N/A						
19	Immokalee PV Solar												
20	Solar		13,381					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,381	25.0%	N/A	25.0%	N/A						
22	Indian River PV Solar												
23	Solar		14,768					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	14,768	27.5%	N/A	27.5%	N/A						
25	Interstate PV Solar												
26	Solar		14,383					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	14,383	26.8%	N/A	26.8%	N/A						
28	Lakeside PV Solar												
29	Solar		13,215					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	13,215	24.6%	N/A	24.6%	N/A						
31	Lauderdale 6A												
32	Gas		4,974				11,289	56,152	1,000,000	56,152	257,087	5.17	4.58
33	Plant Unit Info	216.0	4,974	3.2%	94.0%	3.4%	11,289			56,152	257,087	5.17	
34	Lauderdale 6B												
35	Gas		4,679				11,868	55,531	1,000,000	55,531	254,242	5.43	4.58

FLORIDA POWER & LIGHT COMPANY
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	216.0	4,679	3.0%	94.0%	3.2%	11,868			55,531	254,242	5.43	
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		5,577				11,078	61,781	1,000,000	61,781	282,858	5.07	4.58
5	Plant Unit Info	216.0	5,577	3.6%	94.0%	3.8%	11,078			61,781	282,858	5.07	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		3,945				11,074	43,688	1,000,000	43,688	200,020	5.07	4.58
9	Plant Unit Info	216.0	3,945	2.5%	94.0%	2.7%	11,074			43,688	200,020	5.07	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		4,048				10,945	44,307	1,000,000	44,307	202,854	5.01	4.58
13	Plant Unit Info	216.0	4,048	2.6%	94.0%	2.8%	10,945			44,307	202,854	5.01	
14	Loggerhead PV Solar												
15	Solar		14,530					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,530	27.1%	N/A	27.1%	N/A						
17	Magnolia PV Solar												
18	Solar		14,885					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,885	27.8%	N/A	27.8%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		637,318				6,825	4,349,814	1,000,000	4,349,814	19,518,899	3.06	4.49
30	Plant Unit Info	1,235.0	637,318	71.2%	93.9%	75.8%	6,825			4,349,814	19,518,899	3.06	
31	Manatee PV Solar												
32	Solar		14,433					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	14,433	26.9%	N/A	26.9%	N/A						
34	Martin 3												
35	Gas		170,923				7,313	1,249,892	1,000,000	1,249,892	5,619,688	3.29	4.50

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	464.0	170,923	51.2%	93.4%	54.5%	7,313			1,249,892	5,619,688	3.29	
2	Martin 4												
3	Gas		178,046				7,307	1,300,956	1,000,000	1,300,956	5,851,193	3.29	4.50
4	Plant Unit Info	464.0	178,046	53.3%	93.9%	56.7%	7,307			1,300,956	5,851,193	3.29	
5	Martin 8												
6	Gas		455,173				6,915	3,147,613	1,000,000	3,147,613	14,137,667	3.11	4.49
7	Plant Unit Info	1,224.0	455,173	51.4%	74.3%	69.2%	6,915			3,147,613	14,137,667	3.11	
8	Martin 8 Solar												
9	Solar		13,260					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	13,260	33.5%	N/A	33.5%	N/A						
11	Miami-Dade PV Solar												
12	Solar		13,587					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,587	25.3%	N/A	25.3%	N/A						
14	Nassau PV Solar												
15	Solar		13,430					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,430	25.0%	N/A	25.0%	N/A						
17	Northern Preserve ST Solar												
18	Solar		12,290					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	12,290	22.9%	N/A	22.9%	N/A						
20	OKEECHOBEE 1												
21	Gas		850,424				6,343	5,393,983	1,000,000	5,393,983	24,934,758	2.93	4.62
22	Plant Unit Info	1,603.0	850,424	73.7%	93.0%	79.2%	6,343			5,393,983	24,934,758	2.93	
23	Okeechobee PV Solar												
24	Solar		15,386					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	15,386	28.7%	N/A	28.7%	N/A						
26	Orange Blossom PV Solar												
27	Solar		13,161					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	13,161	24.5%	N/A	24.5%	N/A						
29	Palm Bay PV Solar												
30	Solar		13,090					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	13,090	24.4%	N/A	24.4%	N/A						
32	Pea Ridge												
33	Gas		5,528				15,000	82,920	1,000,000	82,920	385,666	6.98	4.65
34	Plant Unit Info	8.0	5,528	96.0%	100.0%	96.0%	15,000			82,920	385,666	6.98	
35	PEEC												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		3,033				6,358	3,307	5,830,007	19,281	255,493	8.42	77.25
2	Gas		797,976				6,358	5,073,381	1,000,000	5,073,381	23,232,818	2.91	4.58
3	Plant Unit Info	1,254.0	801,009	88.7%	93.0%	95.4%	6,358			5,092,662	23,488,311	2.93	
4	Pelican PV Solar												
5	Solar		13,161					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	13,161	24.5%	N/A	24.5%	N/A						
7	Perdido												
8	Gas		2,031				9,900	20,107	1,000,000	20,107	92,458	4.55	4.60
9	Plant Unit Info	3.0	2,031	94.0%	100.0%	94.0%	9,900			20,107	92,458	4.55	
10	Pioneer Trail PV Solar												
11	Solar		14,304					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	14,304	26.7%	N/A	26.7%	N/A						
13	Riviera 5												
14	Gas		523,469				6,695	3,504,480	1,000,000	3,504,480	16,200,156	3.09	4.62
15	Plant Unit Info	1,308.0	523,469	55.6%	93.4%	59.5%	6,695			3,504,480	16,200,156	3.09	
16	Rodeo PV Solar												
17	Solar		14,150					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	14,150	26.4%	N/A	26.4%	N/A						
19	Sabal Palm PV Solar												
20	Solar		12,996					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,996	24.2%	N/A	24.2%	N/A						
22	Sanford 4												
23	Gas		439,423				6,979	3,066,581	1,000,000	3,066,581	14,316,690	3.26	4.67
24	Plant Unit Info	1,147.0	439,423	53.2%	94.1%	56.6%	6,979			3,066,581	14,316,690	3.26	
25	Sanford 5												
26	Gas		433,856				6,981	3,028,938	1,000,000	3,028,938	14,139,849	3.26	4.67
27	Plant Unit Info	1,147.0	433,856	52.5%	94.1%	55.8%	6,981			3,028,938	14,139,849	3.26	
28	Sawgrass PV Solar												
29	Solar		13,205					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	13,205	24.6%	N/A	24.6%	N/A						
31	Scherer 3												
32	Coal		36,476				10,971	23,539	17,000,000	400,165	1,036,284	2.84	44.02
33	Plant Unit Info	860.0	36,476	5.9%	99.6%	39.1%	10,971			400,165	1,036,284	2.84	
34	Scherer 4												
35	Coal											N/A	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		455,004				6,982	3,176,670	1,000,000	3,176,670	14,774,887	3.25	4.65
4	Plant Unit Info	695.7	455,004	90.8%	93.9%	95.5%	6,982			3,176,670	14,774,887	3.25	
5	Smith A												
6	Plant Unit Info	32.0	0	N/A	97.6%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		18,398					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	18,398	34.3%	N/A	34.3%	N/A						
10	Space Coast												
11	Solar		1,447					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,447	20.1%	100.0%	20.1%	N/A						
13	St Lucie 1												
14	Nuclear		688,631				10,560	7,271,879	1,000,000	7,271,879	3,536,315	0.51	0.49
15	Plant Unit Info	981.0	688,631	97.5%	97.3%	100.0%	10,560			7,271,879	3,536,315	0.51	
16	St Lucie 2												
17	Nuclear		589,637				10,496	6,188,655	1,000,000	6,188,655	2,643,793	0.45	0.43
18	Plant Unit Info	840.0	589,637	97.5%	97.5%	100.0%	10,496			6,188,655	2,643,793	0.45	
19	Sundew PV Solar												
20	Solar		13,339					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,339	24.9%	N/A	24.9%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		15,129					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	15,129	28.2%	N/A	28.2%	N/A						
25	Sweetbay PV Solar												
26	Solar		12,407					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	12,407	23.1%	N/A	23.1%	N/A						
28	Trailside PV Solar												
29	Solar		15,017					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	15,017	28.0%	N/A	28.0%	N/A						
31	Turkey Point 3												
32	Nuclear		587,592				10,818	6,356,806	1,000,000	6,356,806	3,153,611	0.54	0.50
33	Plant Unit Info	837.0	587,592	97.5%	97.5%	100.0%	10,818			6,356,806	3,153,611	0.54	
34	Turkey Point 4												
35	Nuclear		592,488				10,729	6,356,626	1,000,000	6,356,626	3,354,392	0.57	0.53

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	844.0	592,488	97.5%	97.3%	100.0%	10,729			6,356,626	3,354,392	0.57	
2	Turkey Point 5												
3	Gas		550,458				6,893	3,794,541	1,000,000	3,794,541	17,377,045	3.16	4.58
4	Plant Unit Info	1,256.0	550,458	60.9%	93.9%	64.8%	6,893			3,794,541	17,377,045	3.16	
5	Twin Lakes ST Solar												
6	Solar		14,949					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,949	27.9%	N/A	27.9%	N/A						
8	Union Springs PV Solar												
9	Solar		15,055					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,055	28.1%	N/A	28.1%	N/A						
11	WCEC 01												
12	Gas		441,172				6,810	3,004,239	1,000,000	3,004,239	13,482,620	3.06	4.49
13	Plant Unit Info	1,223.0	441,172	50.1%	93.7%	53.5%	6,810			3,004,239	13,482,620	3.06	
14	WCEC 02												
15	Gas		383,221				6,789	2,601,553	1,000,000	2,601,553	11,674,147	3.05	4.49
16	Plant Unit Info	1,223.0	383,221	43.5%	59.8%	72.1%	6,789			2,601,553	11,674,147	3.05	
17	WCEC 03												
18	Gas		571,691				6,744	3,855,643	1,000,000	3,855,643	17,302,424	3.03	4.49
19	Plant Unit Info	1,228.0	571,691	64.7%	93.7%	69.0%	6,744			3,855,643	17,302,424	3.03	
20	Wildflower PV Solar												
21	Solar		14,677					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	14,677	27.4%	N/A	27.4%	N/A						
23	Willow PV Solar												
24	Solar		13,829					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	13,829	25.8%	N/A	25.8%	N/A						
26	System Totals												
27	Plant Unit Info	32,333	12,676,045				7,368			93,395,013	314,758,561	2.48	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Jul - 2022												
2	Babcock Preserve ST Solar												
3	Solar		15,420					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	15,420	27.8%	N/A	27.8%	N/A						
5	Babcock PV Solar												
6	Solar		14,422					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,422	26.0%	N/A	26.0%	N/A						
8	Barefoot PV Solar												
9	Solar		15,838					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,838	28.6%	N/A	28.6%	N/A						
11	Blue Cypress PV Solar												
12	Solar		16,150					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,150	29.1%	N/A	29.1%	N/A						
14	Blue Heron ST Solar												
15	Solar		15,420					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	15,420	27.8%	N/A	27.8%	N/A						
17	Blue Indigo PV Solar												
18	Solar		19,512					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	19,512	35.2%	N/A	35.2%	N/A						
20	Blue Springs PV Solar												
21	Solar		15,431					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	15,431	27.8%	N/A	27.8%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		16,889					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	16,889	30.5%	N/A	30.5%	N/A						
26	CCEC 3												
27	Gas		475,738				6,726	3,199,637	1,000,000	3,199,637	15,122,526	3.18	4.73
28	Plant Unit Info	1,308.0	475,738	48.9%	93.4%	52.3%	6,726			3,199,637	15,122,526	3.18	
29	Citrus PV Solar												
30	Solar		14,809					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	14,809	26.7%	N/A	26.7%	N/A						
32	Coral Farms PV Solar												
33	Solar		16,719					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	16,719	30.2%	N/A	30.2%	N/A						
35	Cotton Creek PV Solar												

FLORIDA POWER & LIGHT COMPANY
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		13,311					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	13,311	24.0%	N/A	24.0%	N/A						
3	Dania Beach												
4	Light Oil		1,193				6,150	1,258	5,829,981	7,334	99,837	8.37	79.36
5	Gas		741,760				6,150	4,561,668	1,000,000	4,561,668	21,191,914	2.86	4.65
6	Plant Unit Info	1,182.0	742,953	84.5%	94.5%	90.1%	6,150			4,569,002	21,291,751	2.87	
7	Daniel 1												
8	Coal											N/A	0.00
9	Plant Unit Info	251.0	0	N/A	93.6%	N/A	N/A						
10	Daniel 2												
11	Coal											N/A	0.00
12	Plant Unit Info	251.0	0	N/A	93.6%	N/A	N/A						
13	Desoto Solar												
14	Solar		4,546					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	4,546	24.4%	N/A	24.4%	N/A						
16	Discovery PV Solar												
17	Solar		12,900					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	12,900	23.3%	N/A	23.3%	N/A						
19	Echo River PV Solar												
20	Solar		19,942					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	19,942	36.0%	N/A	36.0%	N/A						
22	Egret PV Solar												
23	Solar		14,999					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	14,999	27.1%	N/A	27.1%	N/A						
25	Elder Branch PV Solar												
26	Solar		17,174					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	17,174	31.0%	N/A	31.0%	N/A						
28	Fort Drum PV Solar												
29	Solar		12,852					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	12,852	23.2%	N/A	23.2%	N/A						
31	Fort Myers 2												
32	Gas		775,436				7,014	5,438,698	1,000,000	5,438,698	25,719,816	3.32	4.73
33	Plant Unit Info	1,700.0	775,436	61.3%	93.8%	65.4%	7,014			5,438,698	25,719,816	3.32	
34	Fort Myers 3A												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	162.0	0	N/A	93.8%	N/A	N/A						
3	Fort Myers 3B												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		764				11,381	8,695	1,000,000	8,695	41,274	5.40	4.75
6	Plant Unit Info	166.0	764	0.6%	93.8%	0.7%	11,381			8,695	41,274	5.40	
7	Fort Myers 3C												
8	Light Oil		255				10,562	462	5,830,033	2,694	43,920	17.22	95.05
9	Gas		3,795				10,562	40,083	1,000,000	40,083	190,193	5.01	4.74
10	Plant Unit Info	219.0	4,050	2.5%	93.8%	2.7%	10,562			42,777	234,113	5.78	
11	Fort Myers 3D												
12	Light Oil		134				10,518	242	5,829,986	1,408	22,955	17.15	95.05
13	Gas		4,321				10,519	45,453	1,000,000	45,453	215,748	4.99	4.75
14	Plant Unit Info	219.0	4,455	2.7%	93.8%	2.9%	10,519			46,861	238,702	5.36	
15	GCEC 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
18	GCEC 5												
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
21	GCEC 6												
22	Gas		4,375				11,794	51,597	1,000,000	51,597	245,417	5.61	4.76
23	Plant Unit Info	315.0	4,375	2.0%	93.6%	2.2%	11,794			51,597	245,417	5.61	
24	GCEC 7												
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	496.0	0	N/A	93.6%	N/A	N/A						
27	GCEC 8A												
28	Gas		10,115				10,416	105,358	1,000,000	105,358	499,582	4.94	4.74
29	Plant Unit Info	234.5	10,115	5.9%	93.8%	6.3%	10,416			105,358	499,582	4.94	
30	GCEC 8B												
31	Gas		8,711				10,509	91,547	1,000,000	91,547	433,967	4.98	4.74
32	Plant Unit Info	235.0	8,711	5.1%	93.8%	5.4%	10,509			91,547	433,967	4.98	
33	GCEC 8C												
34	Gas		9,038				10,361	93,649	1,000,000	93,649	444,358	4.92	4.74
35	Plant Unit Info	234.5	9,038	5.3%	93.8%	5.7%	10,361			93,649	444,358	4.92	

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		10,448				10,705	111,847	1,000,000	111,847	530,558	5.08	4.74
3	Plant Unit Info	234.5	10,448	6.1%	93.8%	6.5%	10,705			111,847	530,558	5.08	
4	Ghost Orchid PV Solar												
5	Solar		13,814					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	13,814	24.9%	N/A	24.9%	N/A						
7	Grove PV Solar												
8	Solar		14,215					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	14,215	25.7%	N/A	25.7%	N/A						
10	Hammock PV Solar												
11	Solar		15,832					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	15,832	28.6%	N/A	28.6%	N/A						
13	Hibiscus PV Solar												
14	Solar		15,689					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	15,689	28.3%	N/A	28.3%	N/A						
16	Horizon PV Solar												
17	Solar		16,746					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	16,746	30.2%	N/A	30.2%	N/A						
19	Immokalee PV Solar												
20	Solar		13,864					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,864	25.0%	N/A	25.0%	N/A						
22	Indian River PV Solar												
23	Solar		16,135					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	16,135	29.1%	N/A	29.1%	N/A						
25	Interstate PV Solar												
26	Solar		15,280					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	15,280	27.6%	N/A	27.6%	N/A						
28	Lakeside PV Solar												
29	Solar		14,148					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	14,148	25.5%	N/A	25.5%	N/A						
31	Lauderdale 6A												
32	Gas		1,626				11,629	18,908	1,000,000	18,908	87,837	5.40	4.65
33	Plant Unit Info	216.0	1,626	1.0%	94.0%	1.1%	11,629			18,908	87,837	5.40	
34	Lauderdale 6B												
35	Gas		513				14,916	7,652	1,000,000	7,652	35,548	6.93	4.65

FLORIDA POWER & LIGHT COMPANY
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	216.0	513	0.3%	94.0%	0.3%	14,916			7,652	35,548	6.93	
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		1,885				13,282	25,036	1,000,000	25,036	116,304	6.17	4.65
5	Plant Unit Info	216.0	1,885	1.2%	94.0%	1.3%	13,282			25,036	116,304	6.17	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		912				11,019	10,049	1,000,000	10,049	46,684	5.12	4.65
9	Plant Unit Info	216.0	912	0.6%	94.0%	0.6%	11,019			10,049	46,684	5.12	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		1,651				11,546	19,062	1,000,000	19,062	88,551	5.36	4.65
13	Plant Unit Info	216.0	1,651	1.0%	94.0%	1.1%	11,546			19,062	88,551	5.36	
14	Loggerhead PV Solar												
15	Solar		16,009					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	16,009	28.9%	N/A	28.9%	N/A						
17	Magnolia PV Solar												
18	Solar		15,519					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	15,519	28.0%	N/A	28.0%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		696,784				6,796	4,735,133	1,000,000	4,735,133	21,614,946	3.10	4.56
30	Plant Unit Info	1,248.0	696,784	74.0%	93.9%	78.8%	6,796			4,735,133	21,614,946	3.10	
31	Manatee PV Solar												
32	Solar		14,533					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	14,533	26.2%	N/A	26.2%	N/A						
34	Martin 3												
35	Gas		171,748				7,306	1,254,872	1,000,000	1,254,872	5,765,728	3.36	4.59

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	464.0	171,748	49.8%	93.4%	53.0%	7,306			1,254,872	5,765,728	3.36	
2	Martin 4												
3	Gas		180,940				7,308	1,322,274	1,000,000	1,322,274	6,081,186	3.36	4.60
4	Plant Unit Info	464.0	180,940	52.4%	93.9%	55.8%	7,308			1,322,274	6,081,186	3.36	
5	Martin 8												
6	Gas		637,230				6,891	4,390,893	1,000,000	4,390,893	20,173,946	3.17	4.59
7	Plant Unit Info	1,224.0	637,230	69.7%	93.5%	74.5%	6,891			4,390,893	20,173,946	3.17	
8	Martin 8 Solar												
9	Solar		12,679					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	12,679	31.0%	N/A	31.0%	N/A						
11	Miami-Dade PV Solar												
12	Solar		14,897					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,897	26.9%	N/A	26.9%	N/A						
14	Nassau PV Solar												
15	Solar		14,620					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,620	26.4%	N/A	26.4%	N/A						
17	Northern Preserve ST Solar												
18	Solar		13,402					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	13,402	24.2%	N/A	24.2%	N/A						
20	OKEECHOBEE 1												
21	Gas		1,028,198				6,288	6,465,071	1,000,000	6,465,071	30,269,035	2.94	4.68
22	Plant Unit Info	1,603.0	1,028,198	86.2%	93.0%	92.7%	6,288			6,465,071	30,269,035	2.94	
23	Okeechobee PV Solar												
24	Solar		16,177					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	16,177	29.2%	N/A	29.2%	N/A						
26	Orange Blossom PV Solar												
27	Solar		14,337					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	14,337	25.9%	N/A	25.9%	N/A						
29	Palm Bay PV Solar												
30	Solar		14,236					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	14,236	25.7%	N/A	25.7%	N/A						
32	Pea Ridge												
33	Gas		56				14,893	834	1,000,000	834	3,976	7.10	4.77
34	Plant Unit Info	12.0	56	0.6%	93.7%	0.7%	14,893			834	3,976	7.10	
35	PEEC												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		835,885				6,350	5,307,802	1,000,000	5,307,802	24,658,118	2.95	4.65
3	Plant Unit Info	1,254.0	835,885	89.6%	93.0%	96.3%	6,350			5,307,802	24,658,118	2.95	
4	Pelican PV Solar												
5	Solar		14,337					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	14,337	25.9%	N/A	25.9%	N/A						
7	Perdido												
8	Gas		2,123				9,902	21,021	1,000,000	21,021	97,065	4.57	4.62
9	Plant Unit Info	4.0	2,123	71.4%	100.0%	71.4%	9,902			21,021	97,065	4.57	
10	Pioneer Trail PV Solar												
11	Solar		15,188					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	15,188	27.4%	N/A	27.4%	N/A						
13	Riviera 5												
14	Gas		600,040				6,672	4,003,405	1,000,000	4,003,405	18,743,677	3.12	4.68
15	Plant Unit Info	1,308.0	600,040	61.7%	93.4%	66.0%	6,672			4,003,405	18,743,677	3.12	
16	Rodeo PV Solar												
17	Solar		14,826					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	14,826	26.8%	N/A	26.8%	N/A						
19	Sabal Palm PV Solar												
20	Solar		14,072					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	14,072	25.4%	N/A	25.4%	N/A						
22	Sanford 4												
23	Gas		458,150				6,987	3,201,206	1,000,000	3,201,206	15,132,908	3.30	4.73
24	Plant Unit Info	1,147.0	458,150	53.7%	94.1%	57.1%	6,987			3,201,206	15,132,908	3.30	
25	Sanford 5												
26	Gas		458,908				6,994	3,209,744	1,000,000	3,209,744	15,173,208	3.31	4.73
27	Plant Unit Info	1,147.0	458,908	53.8%	94.1%	57.2%	6,994			3,209,744	15,173,208	3.31	
28	Sawgrass PV Solar												
29	Solar		13,817					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	13,817	24.9%	N/A	24.9%	N/A						
31	Scherer 3												
32	Coal											N/A	0.00
33	Plant Unit Info	215.0	0	N/A	93.7%	N/A	N/A						
34	Scherer 4												
35	Coal											N/A	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		315,326				7,001	2,207,672	1,000,000	2,207,672	10,526,695	3.34	4.77
4	Plant Unit Info	652.0	315,326	65.0%	93.9%	69.2%	7,001			2,207,672	10,526,695	3.34	
5	Smith A												
6	Plant Unit Info	32.0	0	N/A	93.8%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		18,794					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	18,794	33.9%	N/A	33.9%	N/A						
10	Space Coast												
11	Solar		1,555					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,555	20.9%	100.0%	20.9%	N/A						
13	St Lucie 1												
14	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,654,191	0.51	0.49
15	Plant Unit Info	981.0	711,586	97.5%	97.3%	100.0%	10,560			7,514,275	3,654,191	0.51	
16	St Lucie 2												
17	Nuclear		609,292				10,496	6,394,944	1,000,000	6,394,944	2,731,920	0.45	0.43
18	Plant Unit Info	840.0	609,292	97.5%	97.5%	100.0%	10,496			6,394,944	2,731,920	0.45	
19	Sundew PV Solar												
20	Solar		14,063					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	14,063	25.4%	N/A	25.4%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		16,190					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	16,190	29.2%	N/A	29.2%	N/A						
25	Sweetbay PV Solar												
26	Solar		13,905					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	13,905	25.1%	N/A	25.1%	N/A						
28	Trailside PV Solar												
29	Solar		15,674					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	15,674	28.3%	N/A	28.3%	N/A						
31	Turkey Point 3												
32	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,258,732	0.54	0.50
33	Plant Unit Info	837.0	607,178	97.5%	97.5%	100.0%	10,818			6,568,699	3,258,732	0.54	
34	Turkey Point 4												
35	Nuclear		612,238				10,729	6,568,514	1,000,000	6,568,514	3,466,205	0.57	0.53

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	844.0	612,238	97.5%	97.3%	100.0%	10,729			6,568,514	3,466,205	0.57	
2	Turkey Point 5												
3	Gas		570,735				6,890	3,932,289	1,000,000	3,932,289	18,268,166	3.20	4.65
4	Plant Unit Info	1,256.0	570,735	61.1%	93.9%	65.0%	6,890			3,932,289	18,268,166	3.20	
5	Twin Lakes ST Solar												
6	Solar		16,435					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	16,435	29.7%	N/A	29.7%	N/A						
8	Union Springs PV Solar												
9	Solar		15,697					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,697	28.3%	N/A	28.3%	N/A						
11	WCEC 01												
12	Gas		489,439				6,802	3,329,014	1,000,000	3,329,014	15,195,518	3.10	4.56
13	Plant Unit Info	1,223.0	489,439	53.8%	93.7%	57.4%	6,802			3,329,014	15,195,518	3.10	
14	WCEC 02												
15	Gas		570,320				6,727	3,836,655	1,000,000	3,836,655	17,513,733	3.07	4.56
16	Plant Unit Info	1,223.0	570,320	62.7%	83.5%	74.6%	6,727			3,836,655	17,513,733	3.07	
17	WCEC 03												
18	Gas		604,093				6,734	4,067,717	1,000,000	4,067,717	18,568,424	3.07	4.56
19	Plant Unit Info	1,228.0	604,093	66.1%	93.7%	70.6%	6,734			4,067,717	18,568,424	3.07	
20	Wildflower PV Solar												
21	Solar		15,980					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	15,980	28.8%	N/A	28.8%	N/A						
23	Willow PV Solar												
24	Solar		15,198					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	15,198	27.4%	N/A	27.4%	N/A						
26	System Totals												
27	Plant Unit Info	31,315	12,967,136				7,108			92,172,409	316,074,364	2.44	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Aug - 2022												
2	Babcock Preserve ST Solar												
3	Solar		14,937					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,937	27.0%	N/A	27.0%	N/A						
5	Babcock PV Solar												
6	Solar		14,342					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,342	25.9%	N/A	25.9%	N/A						
8	Barefoot PV Solar												
9	Solar		15,018					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,018	27.1%	N/A	27.1%	N/A						
11	Blue Cypress PV Solar												
12	Solar		15,243					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	15,243	27.5%	N/A	27.5%	N/A						
14	Blue Heron ST Solar												
15	Solar		14,937					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,937	27.0%	N/A	27.0%	N/A						
17	Blue Indigo PV Solar												
18	Solar		18,386					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	18,386	33.2%	N/A	33.2%	N/A						
20	Blue Springs PV Solar												
21	Solar		14,445					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	14,445	26.1%	N/A	26.1%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		15,651					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	15,651	28.2%	N/A	28.2%	N/A						
26	CCEC 3												
27	Gas		474,513				6,718	3,187,779	1,000,000	3,187,779	15,046,486	3.17	4.72
28	Plant Unit Info	1,308.0	474,513	48.8%	93.4%	52.2%	6,718			3,187,779	15,046,486	3.17	
29	Citrus PV Solar												
30	Solar		14,611					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	14,611	26.4%	N/A	26.4%	N/A						
32	Coral Farms PV Solar												
33	Solar		16,129					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	16,129	29.1%	N/A	29.1%	N/A						
35	Cotton Creek PV Solar												

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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		12,811					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	12,811	23.1%	N/A	23.1%	N/A						
3	Dania Beach												
4	Light Oil		949				6,150	1,001	5,829,986	5,835	79,431	8.37	79.36
5	Gas		736,630				6,150	4,530,425	1,000,000	4,530,425	20,999,449	2.85	4.64
6	Plant Unit Info	1,182.0	737,579	83.9%	94.5%	89.4%	6,150			4,536,260	21,078,881	2.86	
7	Daniel 1												
8	Coal											N/A	0.00
9	Plant Unit Info	251.0	0	N/A	93.6%	N/A	N/A						
10	Daniel 2												
11	Coal											N/A	0.00
12	Plant Unit Info	251.0	0	N/A	93.6%	N/A	N/A						
13	Desoto Solar												
14	Solar		4,326					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	4,326	23.3%	N/A	23.3%	N/A						
16	Discovery PV Solar												
17	Solar		12,412					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	12,412	22.4%	N/A	22.4%	N/A						
19	Echo River PV Solar												
20	Solar		18,710					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	18,710	33.8%	N/A	33.8%	N/A						
22	Egret PV Solar												
23	Solar		13,338					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	13,338	24.1%	N/A	24.1%	N/A						
25	Elder Branch PV Solar												
26	Solar		16,930					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	16,930	30.5%	N/A	30.5%	N/A						
28	Fort Drum PV Solar												
29	Solar		12,697					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	12,697	22.9%	N/A	22.9%	N/A						
31	Fort Myers 2												
32	Gas		797,000				7,013	5,589,215	1,000,000	5,589,215	26,392,492	3.31	4.72
33	Plant Unit Info	1,700.0	797,000	63.0%	93.8%	67.2%	7,013			5,589,215	26,392,492	3.31	
34	Fort Myers 3A												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	162.0	0	N/A	93.8%	N/A	N/A						
3	Fort Myers 3B												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	166.0	0	N/A	93.8%	N/A	N/A						
7	Fort Myers 3C												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		9,315				10,524	98,032	1,000,000	98,032	463,036	4.97	4.72
10	Plant Unit Info	219.0	9,315	5.7%	93.8%	6.1%	10,524			98,032	463,036	4.97	
11	Fort Myers 3D												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		7,290				10,522	76,708	1,000,000	76,708	361,907	4.96	4.72
14	Plant Unit Info	219.0	7,290	4.5%	93.8%	4.8%	10,522			76,708	361,907	4.96	
15	GCEC 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
18	GCEC 5												
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
21	GCEC 6												
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	315.0	0	N/A	93.6%	N/A	N/A						
24	GCEC 7												
25	Gas		6,198				11,455	70,998	1,000,000	70,998	336,467	5.43	4.74
26	Plant Unit Info	496.0	6,198	1.8%	93.6%	1.9%	11,455			70,998	336,467	5.43	
27	GCEC 8A												
28	Gas		13,440				10,742	144,375	1,000,000	144,375	682,243	5.08	4.73
29	Plant Unit Info	234.5	13,440	7.9%	93.8%	8.4%	10,742			144,375	682,243	5.08	
30	GCEC 8B												
31	Gas		12,842				10,571	135,751	1,000,000	135,751	641,587	5.00	4.73
32	Plant Unit Info	235.0	12,842	7.5%	93.8%	8.0%	10,571			135,751	641,587	5.00	
33	GCEC 8C												
34	Gas		15,420				10,614	163,665	1,000,000	163,665	773,633	5.02	4.73
35	Plant Unit Info	234.5	15,420	9.1%	93.8%	9.7%	10,614			163,665	773,633	5.02	

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		14,416				10,850	156,411	1,000,000	156,411	740,519	5.14	4.73
3	Plant Unit Info	234.5	14,416	8.5%	93.8%	9.0%	10,850			156,411	740,519	5.14	
4	Ghost Orchid PV Solar												
5	Solar		13,822					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	13,822	24.9%	N/A	24.9%	N/A						
7	Grove PV Solar												
8	Solar		14,011					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	14,011	25.3%	N/A	25.3%	N/A						
10	Hammock PV Solar												
11	Solar		15,279					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	15,279	27.6%	N/A	27.6%	N/A						
13	Hibiscus PV Solar												
14	Solar		15,424					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	15,424	27.8%	N/A	27.8%	N/A						
16	Horizon PV Solar												
17	Solar		16,140					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	16,140	29.1%	N/A	29.1%	N/A						
19	Immokalee PV Solar												
20	Solar		14,021					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	14,021	25.3%	N/A	25.3%	N/A						
22	Indian River PV Solar												
23	Solar		15,230					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	15,230	27.5%	N/A	27.5%	N/A						
25	Interstate PV Solar												
26	Solar		15,104					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	15,104	27.3%	N/A	27.3%	N/A						
28	Lakeside PV Solar												
29	Solar		13,728					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	13,728	24.8%	N/A	24.8%	N/A						
31	Lauderdale 6A												
32	Gas		3,300				10,771	35,543	1,000,000	35,543	164,762	4.99	4.64
33	Plant Unit Info	216.0	3,300	2.1%	94.0%	2.2%	10,771			35,543	164,762	4.99	
34	Lauderdale 6B												
35	Gas		4,358				11,056	48,181	1,000,000	48,181	223,344	5.12	4.64

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	216.0	4,358	2.7%	94.0%	2.9%	11,056			48,181	223,344	5.12	
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		723				12,332	8,916	1,000,000	8,916	41,330	5.72	4.64
5	Plant Unit Info	216.0	723	0.5%	94.0%	0.5%	12,332			8,916	41,330	5.72	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		692				11,376	7,872	1,000,000	7,872	36,493	5.27	4.64
9	Plant Unit Info	216.0	692	0.4%	94.0%	0.5%	11,376			7,872	36,493	5.27	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		1,783				10,655	18,997	1,000,000	18,997	88,061	4.94	4.64
13	Plant Unit Info	216.0	1,783	1.1%	94.0%	1.2%	10,655			18,997	88,061	4.94	
14	Loggerhead PV Solar												
15	Solar		15,258					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	15,258	27.5%	N/A	27.5%	N/A						
17	Magnolia PV Solar												
18	Solar		14,179					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,179	25.6%	N/A	25.6%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		710,846				6,780	4,819,252	1,000,000	4,819,252	21,957,461	3.09	4.56
30	Plant Unit Info	1,260.0	710,846	74.2%	93.9%	79.1%	6,780			4,819,252	21,957,461	3.09	
31	Manatee PV Solar												
32	Solar		14,390					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	14,390	26.0%	N/A	26.0%	N/A						
34	Martin 3												
35	Gas		180,957				7,330	1,326,384	1,000,000	1,326,384	6,090,499	3.37	4.59

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	464.0	180,957	52.4%	93.4%	55.8%	7,330			1,326,384	6,090,499	3.37	
2	Martin 4												
3	Gas		184,652				7,310	1,349,858	1,000,000	1,349,858	6,197,962	3.36	4.59
4	Plant Unit Info	464.0	184,652	53.5%	93.9%	57.0%	7,310			1,349,858	6,197,962	3.36	
5	Martin 8												
6	Gas		633,391				6,885	4,361,119	1,000,000	4,361,119	20,052,358	3.17	4.60
7	Plant Unit Info	1,224.0	633,391	69.3%	93.5%	74.1%	6,885			4,361,119	20,052,358	3.17	
8	Martin 8 Solar												
9	Solar		11,873					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	11,873	29.0%	N/A	29.0%	N/A						
11	Miami-Dade PV Solar												
12	Solar		14,745					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,745	26.6%	N/A	26.6%	N/A						
14	Nassau PV Solar												
15	Solar		12,931					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,931	23.3%	N/A	23.3%	N/A						
17	Northern Preserve ST Solar												
18	Solar		12,982					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	12,982	23.4%	N/A	23.4%	N/A						
20	OKEECHOBEE 1												
21	Gas		1,050,501				6,281	6,598,223	1,000,000	6,598,223	30,819,793	2.93	4.67
22	Plant Unit Info	1,603.0	1,050,501	88.1%	93.0%	94.7%	6,281			6,598,223	30,819,793	2.93	
23	Okeechobee PV Solar												
24	Solar		15,842					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	15,842	28.6%	N/A	28.6%	N/A						
26	Orange Blossom PV Solar												
27	Solar		13,405					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	13,405	24.2%	N/A	24.2%	N/A						
29	Palm Bay PV Solar												
30	Solar		13,282					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	13,282	24.0%	N/A	24.0%	N/A						
32	Pea Ridge												
33	Gas		154				15,000	2,310	1,000,000	2,310	10,996	7.14	4.76
34	Plant Unit Info	12.0	154	1.7%	93.7%	1.8%	15,000			2,310	10,996	7.14	
35	PEEC												

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		839,006				6,347	5,325,585	1,000,000	5,325,585	24,685,342	2.94	4.64
3	Plant Unit Info	1,254.0	839,006	89.9%	93.0%	96.7%	6,347			5,325,585	24,685,342	2.94	
4	Pelican PV Solar												
5	Solar		13,405					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	13,405	24.2%	N/A	24.2%	N/A						
7	Perdido												
8	Gas		2,123				9,902	21,021	1,000,000	21,021	96,682	4.55	4.60
9	Plant Unit Info	4.0	2,123	71.4%	100.0%	71.4%	9,902			21,021	96,682	4.55	
10	Pioneer Trail PV Solar												
11	Solar		15,069					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	15,069	27.2%	N/A	27.2%	N/A						
13	Riviera 5												
14	Gas		590,988				6,674	3,944,197	1,000,000	3,944,197	18,423,041	3.12	4.67
15	Plant Unit Info	1,308.0	590,988	60.7%	93.4%	65.0%	6,674			3,944,197	18,423,041	3.12	
16	Rodeo PV Solar												
17	Solar		14,363					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	14,363	25.9%	N/A	25.9%	N/A						
19	Sabal Palm PV Solar												
20	Solar		13,623					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,623	24.6%	N/A	24.6%	N/A						
22	Sanford 4												
23	Gas		488,523				6,942	3,391,318	1,000,000	3,391,318	16,009,012	3.28	4.72
24	Plant Unit Info	1,147.0	488,523	57.3%	94.1%	60.9%	6,942			3,391,318	16,009,012	3.28	
25	Sanford 5												
26	Gas		486,887				6,943	3,380,539	1,000,000	3,380,539	15,957,341	3.28	4.72
27	Plant Unit Info	1,147.0	486,887	57.1%	94.1%	60.6%	6,943			3,380,539	15,957,341	3.28	
28	Sawgrass PV Solar												
29	Solar		13,840					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	13,840	25.0%	N/A	25.0%	N/A						
31	Scherer 3												
32	Coal											N/A	0.00
33	Plant Unit Info	215.0	0	N/A	93.7%	N/A	N/A						
34	Scherer 4												
35	Coal											N/A	0.00

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		304,701				7,006	2,134,761	1,000,000	2,134,761	10,161,940	3.34	4.76
4	Plant Unit Info	652.0	304,701	62.8%	93.9%	66.9%	7,006			2,134,761	10,161,940	3.34	
5	Smith A												
6	Plant Unit Info	32.0	0	N/A	93.8%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		18,357					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	18,357	33.1%	N/A	33.1%	N/A						
10	Space Coast												
11	Solar		1,545					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,545	20.8%	100.0%	20.8%	N/A						
13	St Lucie 1												
14	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,654,191	0.51	0.49
15	Plant Unit Info	981.0	711,586	97.5%	97.3%	100.0%	10,560			7,514,275	3,654,191	0.51	
16	St Lucie 2												
17	Nuclear		609,292				10,496	6,394,944	1,000,000	6,394,944	2,731,920	0.45	0.43
18	Plant Unit Info	840.0	609,292	97.5%	97.5%	100.0%	10,496			6,394,944	2,731,920	0.45	
19	Sundew PV Solar												
20	Solar		13,920					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,920	25.1%	N/A	25.1%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		15,292					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	15,292	27.6%	N/A	27.6%	N/A						
25	Sweetbay PV Solar												
26	Solar		13,274					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	13,274	24.0%	N/A	24.0%	N/A						
28	Trailside PV Solar												
29	Solar		14,652					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	14,652	26.4%	N/A	26.4%	N/A						
31	Turkey Point 3												
32	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,258,732	0.54	0.50
33	Plant Unit Info	837.0	607,178	97.5%	97.5%	100.0%	10,818			6,568,699	3,258,732	0.54	
34	Turkey Point 4												
35	Nuclear		612,238				10,729	6,568,514	1,000,000	6,568,514	3,466,205	0.57	0.53

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	844.0	612,238	97.5%	97.3%	100.0%	10,729			6,568,514	3,466,205	0.57	
2	Turkey Point 5												
3	Gas		565,071				6,884	3,890,222	1,000,000	3,890,222	18,031,733	3.19	4.64
4	Plant Unit Info	1,256.0	565,071	60.5%	93.9%	64.4%	6,884			3,890,222	18,031,733	3.19	
5	Twin Lakes ST Solar												
6	Solar		15,230					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,230	27.5%	N/A	27.5%	N/A						
8	Union Springs PV Solar												
9	Solar		14,342					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,342	25.9%	N/A	25.9%	N/A						
11	WCEC 01												
12	Gas		431,848				6,855	2,960,470	1,000,000	2,960,470	13,487,786	3.12	4.56
13	Plant Unit Info	1,223.0	431,848	47.5%	93.7%	50.6%	6,855			2,960,470	13,487,786	3.12	
14	WCEC 02												
15	Gas		682,135				6,668	4,548,701	1,000,000	4,548,701	20,724,757	3.04	4.56
16	Plant Unit Info	1,223.0	682,135	75.0%	93.2%	80.0%	6,668			4,548,701	20,724,757	3.04	
17	WCEC 03												
18	Gas		563,739				6,758	3,809,935	1,000,000	3,809,935	17,358,772	3.08	4.56
19	Plant Unit Info	1,228.0	563,739	61.7%	93.7%	65.8%	6,758			3,809,935	17,358,772	3.08	
20	Wildflower PV Solar												
21	Solar		15,359					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	15,359	27.7%	N/A	27.7%	N/A						
23	Willow PV Solar												
24	Solar		14,101					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	14,101	25.4%	N/A	25.4%	N/A						
26	System Totals												
27	Plant Unit Info	31,327	13,077,625				7,126			93,189,030	320,247,763	2.45	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Sep - 2022												
2	Babcock Preserve ST Solar												
3	Solar		14,167					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,167	26.4%	N/A	26.4%	N/A						
5	Babcock PV Solar												
6	Solar		12,899					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,899	24.1%	N/A	24.1%	N/A						
8	Barefoot PV Solar												
9	Solar		13,957					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,957	26.0%	N/A	26.0%	N/A						
11	Blue Cypress PV Solar												
12	Solar		14,290					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,290	26.6%	N/A	26.6%	N/A						
14	Blue Heron ST Solar												
15	Solar		14,167					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,167	26.4%	N/A	26.4%	N/A						
17	Blue Indigo PV Solar												
18	Solar		16,507					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	16,507	30.8%	N/A	30.8%	N/A						
20	Blue Springs PV Solar												
21	Solar		12,988					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	12,988	24.2%	N/A	24.2%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		14,415					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	14,415	26.9%	N/A	26.9%	N/A						
26	CCEC 3												
27	Gas		461,500				6,718	3,100,449	1,000,000	3,100,449	14,599,950	3.16	4.71
28	Plant Unit Info	1,308.0	461,500	49.0%	93.4%	52.4%	6,718			3,100,449	14,599,950	3.16	
29	Citrus PV Solar												
30	Solar		13,630					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	13,630	25.4%	N/A	25.4%	N/A						
32	Coral Farms PV Solar												
33	Solar		14,602					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	14,602	27.2%	N/A	27.2%	N/A						
35	Cotton Creek PV Solar												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		12,183					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	12,183	22.7%	N/A	22.7%	N/A						
3	Dania Beach												
4	Light Oil		232				6,149	245	5,830,035	1,429	19,453	8.37	79.36
5	Gas		711,426				6,149	4,374,696	1,000,000	4,374,696	20,230,867	2.84	4.62
6	Plant Unit Info	1,182.0	711,658	83.6%	94.5%	89.2%	6,149			4,376,125	20,250,319	2.85	
7	Daniel 1												
8	Coal											N/A	0.00
9	Plant Unit Info	251.0	0	N/A	83.6%	N/A	N/A						
10	Daniel 2												
11	Coal											N/A	0.00
12	Plant Unit Info	251.0	0	N/A	93.6%	N/A	N/A						
13	Desoto Solar												
14	Solar		3,868					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	3,868	21.5%	N/A	21.5%	N/A						
16	Discovery PV Solar												
17	Solar		11,389					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	11,389	21.2%	N/A	21.2%	N/A						
19	Echo River PV Solar												
20	Solar		16,335					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	16,335	30.5%	N/A	30.5%	N/A						
22	Egret PV Solar												
23	Solar		11,797					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	11,797	22.0%	N/A	22.0%	N/A						
25	Elder Branch PV Solar												
26	Solar		15,289					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	15,289	28.5%	N/A	28.5%	N/A						
28	Fort Drum PV Solar												
29	Solar		11,487					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	11,487	21.4%	N/A	21.4%	N/A						
31	Fort Myers 2												
32	Gas		786,800				7,008	5,513,931	1,000,000	5,513,931	25,976,937	3.30	4.71
33	Plant Unit Info	1,700.0	786,800	64.3%	93.8%	68.5%	7,008			5,513,931	25,976,937	3.30	
34	Fort Myers 3A												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
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ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	162.0	0	N/A	93.8%	N/A	N/A						
3	Fort Myers 3B												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	166.0	0	N/A	93.8%	N/A	N/A						
7	Fort Myers 3C												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		9,720				10,512	102,177	1,000,000	102,177	482,648	4.97	4.72
10	Plant Unit Info	219.0	9,720	6.2%	93.8%	6.6%	10,512			102,177	482,648	4.97	
11	Fort Myers 3D												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		7,898				10,499	82,925	1,000,000	82,925	391,573	4.96	4.72
14	Plant Unit Info	219.0	7,898	5.0%	93.8%	5.3%	10,499			82,925	391,573	4.96	
15	GCEC 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
18	GCEC 5												
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
21	GCEC 6												
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	315.0	0	N/A	93.6%	N/A	N/A						
24	GCEC 7												
25	Gas		12,387				11,209	138,847	1,000,000	138,847	658,221	5.31	4.74
26	Plant Unit Info	496.0	12,387	3.6%	93.6%	3.8%	11,209			138,847	658,221	5.31	
27	GCEC 8A												
28	Gas		14,875				10,326	153,602	1,000,000	153,602	726,397	4.88	4.73
29	Plant Unit Info	234.5	14,875	9.0%	93.8%	9.6%	10,326			153,602	726,397	4.88	
30	GCEC 8B												
31	Gas		13,347				10,340	138,012	1,000,000	138,012	653,509	4.90	4.74
32	Plant Unit Info	235.0	13,347	8.1%	93.8%	8.6%	10,340			138,012	653,509	4.90	
33	GCEC 8C												
34	Gas		13,835				10,433	144,342	1,000,000	144,342	682,278	4.93	4.73
35	Plant Unit Info	234.5	13,835	8.4%	93.8%	8.9%	10,433			144,342	682,278	4.93	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		15,724				10,522	165,441	1,000,000	165,441	783,165	4.98	4.73
3	Plant Unit Info	234.5	15,724	9.5%	93.8%	10.2%	10,522			165,441	783,165	4.98	
4	Ghost Orchid PV Solar												
5	Solar		12,885					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	12,885	24.0%	N/A	24.0%	N/A						
7	Grove PV Solar												
8	Solar		12,944					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	12,944	24.1%	N/A	24.1%	N/A						
10	Hammock PV Solar												
11	Solar		14,411					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	14,411	26.9%	N/A	26.9%	N/A						
13	Hibiscus PV Solar												
14	Solar		13,975					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	13,975	26.1%	N/A	26.1%	N/A						
16	Horizon PV Solar												
17	Solar		14,806					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	14,806	27.6%	N/A	27.6%	N/A						
19	Immokalee PV Solar												
20	Solar		13,071					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,071	24.4%	N/A	24.4%	N/A						
22	Indian River PV Solar												
23	Solar		14,277					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	14,277	26.6%	N/A	26.6%	N/A						
25	Interstate PV Solar												
26	Solar		14,079					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	14,079	26.3%	N/A	26.3%	N/A						
28	Lakeside PV Solar												
29	Solar		12,736					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	12,736	23.7%	N/A	23.7%	N/A						
31	Lauderdale 6A												
32	Gas		5,398				11,618	62,716	1,000,000	62,716	290,028	5.37	4.62
33	Plant Unit Info	216.0	5,398	3.5%	94.0%	3.7%	11,618			62,716	290,028	5.37	
34	Lauderdale 6B												
35	Gas		0					0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		2,766				12,307	34,042	1,000,000	34,042	157,426	5.69	4.62
5	Plant Unit Info	216.0	2,766	1.8%	94.0%	1.9%	12,307			34,042	157,426	5.69	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		1,553				10,792	16,760	1,000,000	16,760	77,506	4.99	4.62
9	Plant Unit Info	216.0	1,553	1.0%	94.0%	1.1%	10,792			16,760	77,506	4.99	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		1,528				11,990	18,321	1,000,000	18,321	84,724	5.54	4.62
13	Plant Unit Info	216.0	1,528	1.0%	94.0%	1.1%	11,990			18,321	84,724	5.54	
14	Loggerhead PV Solar												
15	Solar		14,449					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,449	26.9%	N/A	26.9%	N/A						
17	Magnolia PV Solar												
18	Solar		12,435					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	12,435	23.2%	N/A	23.2%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		712,873				6,758	4,817,557	1,000,000	4,817,557	21,889,419	3.07	4.54
30	Plant Unit Info	1,272.0	712,873	75.8%	93.9%	80.7%	6,758			4,817,557	21,889,419	3.07	
31	Manatee PV Solar												
32	Solar		13,678					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	13,678	25.5%	N/A	25.5%	N/A						
34	Martin 3												
35	Gas		175,002				7,323	1,281,568	1,000,000	1,281,568	5,865,282	3.35	4.58

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	464.0	175,002	52.4%	93.4%	55.8%	7,323			1,281,568	5,865,282	3.35	
2	Martin 4												
3	Gas		182,009				7,309	1,330,241	1,000,000	1,330,241	6,088,008	3.34	4.58
4	Plant Unit Info	464.0	182,009	54.5%	93.9%	58.0%	7,309			1,330,241	6,088,008	3.34	
5	Martin 8												
6	Gas		622,124				6,886	4,283,983	1,000,000	4,283,983	19,629,186	3.16	4.58
7	Plant Unit Info	1,224.0	622,124	70.3%	93.5%	75.2%	6,886			4,283,983	19,629,186	3.16	
8	Martin 8 Solar												
9	Solar		10,320					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	10,320	26.1%	N/A	26.1%	N/A						
11	Miami-Dade PV Solar												
12	Solar		13,518					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,518	25.2%	N/A	25.2%	N/A						
14	Nassau PV Solar												
15	Solar		11,335					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	11,335	21.1%	N/A	21.1%	N/A						
17	Northern Preserve ST Solar												
18	Solar		12,314					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	12,314	23.0%	N/A	23.0%	N/A						
20	OKEECHOBEE 1												
21	Gas		1,024,296				6,279	6,431,724	1,000,000	6,431,724	29,963,341	2.93	4.66
22	Plant Unit Info	1,603.0	1,024,296	88.8%	93.0%	95.4%	6,279			6,431,724	29,963,341	2.93	
23	Okeechobee PV Solar												
24	Solar		14,608					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	14,608	27.2%	N/A	27.2%	N/A						
26	Orange Blossom PV Solar												
27	Solar		12,397					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	12,397	23.1%	N/A	23.1%	N/A						
29	Palm Bay PV Solar												
30	Solar		12,260					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	12,260	22.9%	N/A	22.9%	N/A						
32	Pea Ridge												
33	Gas		22				15,000	330	1,000,000	330	1,567	7.12	4.75
34	Plant Unit Info	12.0	22	0.3%	93.7%	0.3%	15,000			330	1,567	7.12	
35	PEEC												

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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		809,219				6,349	5,137,613	1,000,000	5,137,613	23,758,969	2.94	4.62
3	Plant Unit Info	1,254.0	809,219	89.6%	93.0%	96.4%	6,349			5,137,613	23,758,969	2.94	
4	Pelican PV Solar												
5	Solar		12,397					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	12,397	23.1%	N/A	23.1%	N/A						
7	Perdido												
8	Gas		2,055				9,899	20,343	1,000,000	20,343	93,670	4.56	4.60
9	Plant Unit Info	4.0	2,055	71.4%	100.0%	71.4%	9,899			20,343	93,670	4.56	
10	Pioneer Trail PV Solar												
11	Solar		13,694					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	13,694	25.5%	N/A	25.5%	N/A						
13	Riviera 5												
14	Gas		581,012				6,668	3,874,341	1,000,000	3,874,341	18,049,313	3.11	4.66
15	Plant Unit Info	1,308.0	581,012	61.7%	93.4%	66.0%	6,668			3,874,341	18,049,313	3.11	
16	Rodeo PV Solar												
17	Solar		13,109					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	13,109	24.4%	N/A	24.4%	N/A						
19	Sabal Palm PV Solar												
20	Solar		12,575					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,575	23.4%	N/A	23.4%	N/A						
22	Sanford 4												
23	Gas		490,700				6,946	3,408,279	1,000,000	3,408,279	16,053,719	3.27	4.71
24	Plant Unit Info	1,147.0	490,700	59.4%	94.1%	63.2%	6,946			3,408,279	16,053,719	3.27	
25	Sanford 5												
26	Gas		487,338				6,945	3,384,449	1,000,000	3,384,449	15,940,837	3.27	4.71
27	Plant Unit Info	1,147.0	487,338	59.0%	94.1%	62.7%	6,945			3,384,449	15,940,837	3.27	
28	Sawgrass PV Solar												
29	Solar		12,813					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	12,813	23.9%	N/A	23.9%	N/A						
31	Scherer 3												
32	Coal		23,558				11,155	15,459	16,999,998	262,796	682,226	2.90	44.13
33	Plant Unit Info	215.0	23,558	15.2%	93.7%	16.2%	11,155			262,796	682,226	2.90	
34	Scherer 4												
35	Coal											N/A	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		118,883				7,035	836,374	1,000,000	836,374	3,971,170	3.34	4.75
4	Plant Unit Info	652.0	118,883	25.3%	63.9%	39.6%	7,035			836,374	3,971,170	3.34	
5	Smith A												
6	Plant Unit Info	32.0	0	N/A	93.8%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		16,374					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	16,374	30.5%	N/A	30.5%	N/A						
10	Space Coast												
11	Solar		1,421					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,421	19.7%	100.0%	19.7%	N/A						
13	St Lucie 1												
14	Nuclear		45,909				10,560	484,792	1,000,000	484,792	235,755	0.51	0.49
15	Plant Unit Info	981.0	45,909	4.2%	6.5%	100.0%	10,560			484,792	235,755	0.51	
16	St Lucie 2												
17	Nuclear		589,637				10,496	6,188,655	1,000,000	6,188,655	2,643,793	0.45	0.43
18	Plant Unit Info	840.0	589,637	97.5%	97.5%	100.0%	10,496			6,188,655	2,643,793	0.45	
19	Sundew PV Solar												
20	Solar		12,936					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,936	24.1%	N/A	24.1%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		14,199					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	14,199	26.5%	N/A	26.5%	N/A						
25	Sweetbay PV Solar												
26	Solar		12,663					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	12,663	23.6%	N/A	23.6%	N/A						
28	Trailside PV Solar												
29	Solar		12,560					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	12,560	23.4%	N/A	23.4%	N/A						
31	Turkey Point 3												
32	Nuclear		587,592				10,818	6,356,806	1,000,000	6,356,806	3,153,611	0.54	0.50
33	Plant Unit Info	837.0	587,592	97.5%	97.5%	100.0%	10,818			6,356,806	3,153,611	0.54	
34	Turkey Point 4												
35	Nuclear		592,488				10,729	6,356,626	1,000,000	6,356,626	3,354,392	0.57	0.53

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	844.0	592,488	97.5%	97.3%	100.0%	10,729			6,356,626	3,354,392	0.57	
2	Turkey Point 5												
3	Gas		550,274				6,890	3,791,597	1,000,000	3,791,597	17,534,328	3.19	4.62
4	Plant Unit Info	1,256.0	550,274	60.9%	93.9%	64.8%	6,890			3,791,597	17,534,328	3.19	
5	Twin Lakes ST Solar												
6	Solar		14,028					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,028	26.2%	N/A	26.2%	N/A						
8	Union Springs PV Solar												
9	Solar		12,577					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,577	23.5%	N/A	23.5%	N/A						
11	WCEC 01												
12	Gas		421,745				6,797	2,866,765	1,000,000	2,866,765	13,025,646	3.09	4.54
13	Plant Unit Info	1,223.0	421,745	47.9%	75.9%	63.1%	6,797			2,866,765	13,025,646	3.09	
14	WCEC 02												
15	Gas		667,479				6,669	4,451,271	1,000,000	4,451,271	20,225,092	3.03	4.54
16	Plant Unit Info	1,223.0	667,479	75.8%	93.2%	80.9%	6,669			4,451,271	20,225,092	3.03	
17	WCEC 03												
18	Gas		558,381				6,756	3,772,417	1,000,000	3,772,417	17,140,484	3.07	4.54
19	Plant Unit Info	1,228.0	558,381	63.2%	93.7%	67.4%	6,756			3,772,417	17,140,484	3.07	
20	Wildflower PV Solar												
21	Solar		14,791					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	14,791	27.6%	N/A	27.6%	N/A						
23	Willow PV Solar												
24	Solar		13,002					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	13,002	24.2%	N/A	24.2%	N/A						
26	System Totals												
27	Plant Unit Info	31,339	11,965,192				6,969			83,386,218	305,114,487	2.55	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Oct - 2022												
2	Babcock Preserve ST Solar												
3	Solar		14,948					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,948	27.0%	N/A	27.0%	N/A						
5	Babcock PV Solar												
6	Solar		13,941					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,941	25.2%	N/A	25.2%	N/A						
8	Barefoot PV Solar												
9	Solar		14,309					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,309	25.8%	N/A	25.8%	N/A						
11	Blue Cypress PV Solar												
12	Solar		14,540					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,540	26.2%	N/A	26.2%	N/A						
14	Blue Heron ST Solar												
15	Solar		14,948					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,948	27.0%	N/A	27.0%	N/A						
17	Blue Indigo PV Solar												
18	Solar		15,970					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	15,970	28.8%	N/A	28.8%	N/A						
20	Blue Springs PV Solar												
21	Solar		12,549					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	12,549	22.6%	N/A	22.6%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		14,269					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	14,269	25.7%	N/A	25.7%	N/A						
26	CCEC 3												
27	Gas		435,576				6,749	2,939,752	1,000,000	2,939,752	14,574,641	3.35	4.96
28	Plant Unit Info	1,308.0	435,576	44.8%	93.4%	47.9%	6,749			2,939,752	14,574,641	3.35	
29	Citrus PV Solar												
30	Solar		14,046					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	14,046	25.3%	N/A	25.3%	N/A						
32	Coral Farms PV Solar												
33	Solar		15,020					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	15,020	27.1%	N/A	27.1%	N/A						
35	Cotton Creek PV Solar												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		12,367					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	12,367	22.3%	N/A	22.3%	N/A						
3	Dania Beach												
4	Light Oil		21				6,140	22	5,829,191	129	1,756	8.36	79.35
5	Gas		758,181				6,140	4,655,208	1,000,000	4,655,208	22,615,136	2.98	4.86
6	Plant Unit Info	1,182.0	758,202	86.2%	94.5%	91.9%	6,140			4,655,337	22,616,892	2.98	
7	Daniel 1												
8	Coal											N/A	0.00
9	Plant Unit Info	251.0	0	N/A	N/A	N/A	N/A						
10	Daniel 2												
11	Coal											N/A	0.00
12	Plant Unit Info	251.0	0	N/A	64.6%	N/A	N/A						
13	Desoto Solar												
14	Solar		3,833					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	3,833	20.6%	N/A	20.6%	N/A						
16	Discovery PV Solar												
17	Solar		11,518					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	11,518	20.8%	N/A	20.8%	N/A						
19	Echo River PV Solar												
20	Solar		16,339					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	16,339	29.5%	N/A	29.5%	N/A						
22	Egret PV Solar												
23	Solar		11,683					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	11,683	21.1%	N/A	21.1%	N/A						
25	Elder Branch PV Solar												
26	Solar		15,677					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	15,677	28.3%	N/A	28.3%	N/A						
28	Fort Drum PV Solar												
29	Solar		11,407					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	11,407	20.6%	N/A	20.6%	N/A						
31	Fort Myers 2												
32	Gas		798,174				7,015	5,599,050	1,000,000	5,599,050	27,776,470	3.48	4.96
33	Plant Unit Info	1,700.0	798,174	63.1%	93.8%	67.3%	7,015			5,599,050	27,776,470	3.48	
34	Fort Myers 3A												
35	Light Oil		593				11,729	1,193	5,829,980	6,954	113,371	19.12	95.05

FLORIDA POWER & LIGHT COMPANY
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SCHEDULE: E4

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		898				11,729	10,534	1,000,000	10,534	52,380	5.83	4.97
2	Plant Unit Info	162.0	1,491	1.2%	93.8%	1.3%	11,729			17,488	165,751	11.12	
3	Fort Myers 3B												
4	Light Oil		452				11,489	891	5,830,014	5,196	84,710	18.73	95.05
5	Gas		1,840				11,490	21,138	1,000,000	21,138	105,284	5.72	4.98
6	Plant Unit Info	166.0	2,292	1.9%	93.8%	2.0%	11,490			26,334	189,994	8.29	
7	Fort Myers 3C												
8	Light Oil		554				10,650	1,012	5,829,973	5,899	96,171	17.36	95.05
9	Gas		2,835				10,650	30,193	1,000,000	30,193	150,018	5.29	4.97
10	Plant Unit Info	219.0	3,389	2.1%	93.8%	2.2%	10,650			36,092	246,189	7.26	
11	Fort Myers 3D												
12	Light Oil		421				10,711	773	5,830,002	4,507	73,477	17.46	95.05
13	Gas		2,909				10,711	31,162	1,000,000	31,162	155,014	5.33	4.97
14	Plant Unit Info	219.0	3,330	2.0%	93.8%	2.2%	10,711			35,669	228,492	6.86	
15	GCEC 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
18	GCEC 5												
19	Gas		2,161				13,423	29,007	1,000,000	29,007	134,247	6.21	4.63
20	Plant Unit Info	78.0	2,161	3.7%	93.6%	4.0%	13,423			29,007	134,247	6.21	
21	GCEC 6												
22	Gas		4,031				11,932	48,094	1,000,000	48,094	239,541	5.94	4.98
23	Plant Unit Info	315.0	4,031	1.9%	93.6%	2.0%	11,932			48,094	239,541	5.94	
24	GCEC 7												
25	Gas		13,180				11,338	149,446	1,000,000	149,446	743,632	5.64	4.98
26	Plant Unit Info	496.0	13,180	3.8%	93.6%	4.0%	11,338			149,446	743,632	5.64	
27	GCEC 8A												
28	Gas		12,552				10,227	128,372	1,000,000	128,372	637,442	5.08	4.97
29	Plant Unit Info	234.5	12,552	7.3%	93.8%	7.8%	10,227			128,372	637,442	5.08	
30	GCEC 8B												
31	Gas		11,187				10,175	113,825	1,000,000	113,825	565,099	5.05	4.96
32	Plant Unit Info	235.0	11,187	6.5%	93.8%	7.0%	10,175			113,825	565,099	5.05	
33	GCEC 8C												
34	Gas		11,518				10,222	117,741	1,000,000	117,741	584,917	5.08	4.97
35	Plant Unit Info	234.5	11,518	6.7%	93.8%	7.2%	10,222			117,741	584,917	5.08	

FLORIDA POWER & LIGHT COMPANY
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ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		10,036				10,385	104,227	1,000,000	104,227	518,290	5.16	4.97
3	Plant Unit Info	234.5	10,036	5.9%	93.8%	6.3%	10,385			104,227	518,290	5.16	
4	Ghost Orchid PV Solar												
5	Solar		13,573					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	13,573	24.5%	N/A	24.5%	N/A						
7	Grove PV Solar												
8	Solar		13,268					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	13,268	23.9%	N/A	23.9%	N/A						
10	Hammock PV Solar												
11	Solar		15,340					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	15,340	27.7%	N/A	27.7%	N/A						
13	Hibiscus PV Solar												
14	Solar		13,972					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	13,972	25.2%	N/A	25.2%	N/A						
16	Horizon PV Solar												
17	Solar		15,171					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	15,171	27.4%	N/A	27.4%	N/A						
19	Immokalee PV Solar												
20	Solar		13,933					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,933	25.1%	N/A	25.1%	N/A						
22	Indian River PV Solar												
23	Solar		14,532					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	14,532	26.2%	N/A	26.2%	N/A						
25	Interstate PV Solar												
26	Solar		14,238					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	14,238	25.7%	N/A	25.7%	N/A						
28	Lakeside PV Solar												
29	Solar		12,782					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	12,782	23.1%	N/A	23.1%	N/A						
31	Lauderdale 6A												
32	Gas		4,814				10,516	50,623	1,000,000	50,623	245,862	5.11	4.86
33	Plant Unit Info	216.0	4,814	3.0%	94.0%	3.2%	10,516			50,623	245,862	5.11	
34	Lauderdale 6B												
35	Gas		5,617				10,479	58,860	1,000,000	58,860	285,868	5.09	4.86

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	216.0	5,617	3.5%	94.0%	3.7%	10,479			58,860	285,868	5.09	
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		6,219				10,506	65,338	1,000,000	65,338	317,329	5.10	4.86
5	Plant Unit Info	216.0	6,219	3.9%	94.0%	4.1%	10,506			65,338	317,329	5.10	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		5,817				10,524	61,219	1,000,000	61,219	297,326	5.11	4.86
9	Plant Unit Info	216.0	5,817	3.6%	94.0%	3.9%	10,524			61,219	297,326	5.11	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		6,820				10,530	71,816	1,000,000	71,816	348,791	5.11	4.86
13	Plant Unit Info	216.0	6,820	4.2%	94.0%	4.5%	10,530			71,816	348,791	5.11	
14	Loggerhead PV Solar												
15	Solar		14,876					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,876	26.8%	N/A	26.8%	N/A						
17	Magnolia PV Solar												
18	Solar		12,256					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	12,256	22.1%	N/A	22.1%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		544,976				6,745	3,675,785	1,000,000	3,675,785	17,518,119	3.21	4.77
30	Plant Unit Info	1,272.0	544,976	56.0%	59.2%	94.6%	6,745			3,675,785	17,518,119	3.21	
31	Manatee PV Solar												
32	Solar		14,472					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	14,472	26.1%	N/A	26.1%	N/A						
34	Martin 3												
35	Gas		6,568				7,343	48,227	1,000,000	48,227	231,242	3.52	4.79

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	464.0	6,568	1.9%	6.3%	27.9%	7,343			48,227	231,242	3.52	
2	Martin 4												
3	Gas		187,680				7,312	1,372,263	1,000,000	1,372,263	6,550,814	3.49	4.77
4	Plant Unit Info	464.0	187,680	54.4%	93.9%	57.9%	7,312			1,372,263	6,550,814	3.49	
5	Martin 8												
6	Gas		655,029				6,866	4,497,497	1,000,000	4,497,497	21,445,881	3.27	4.77
7	Plant Unit Info	1,224.0	655,029	71.6%	93.5%	76.6%	6,866			4,497,497	21,445,881	3.27	
8	Martin 8 Solar												
9	Solar		9,114					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	9,114	22.3%	N/A	22.3%	N/A						
11	Miami-Dade PV Solar												
12	Solar		13,970					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,970	25.2%	N/A	25.2%	N/A						
14	Nassau PV Solar												
15	Solar		11,267					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	11,267	20.3%	N/A	20.3%	N/A						
17	Northern Preserve ST Solar												
18	Solar		12,992					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	12,992	23.4%	N/A	23.4%	N/A						
20	OKEECHOBEE 1												
21	Gas		692,376				6,349	4,395,799	1,000,000	4,395,799	21,570,602	3.12	4.91
22	Plant Unit Info	1,603.0	692,376	58.1%	59.7%	97.3%	6,349			4,395,799	21,570,602	3.12	
23	Okeechobee PV Solar												
24	Solar		14,662					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	14,662	26.5%	N/A	26.5%	N/A						
26	Orange Blossom PV Solar												
27	Solar		12,418					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	12,418	22.4%	N/A	22.4%	N/A						
29	Palm Bay PV Solar												
30	Solar		12,264					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	12,264	22.1%	N/A	22.1%	N/A						
32	Pea Ridge												
33	Gas		89				14,966	1,332	1,000,000	1,332	6,648	7.47	4.99
34	Plant Unit Info	12.0	89	1.0%	93.7%	1.1%	14,966			1,332	6,648	7.47	
35	PEEC												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		246,466				6,340	1,562,563	1,000,000	1,562,563	7,588,949	3.08	4.86
3	Plant Unit Info	1,254.0	246,466	22.0%	22.0%	100.0%	6,340			1,562,563	7,588,949	3.08	
4	Pelican PV Solar												
5	Solar		12,418					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	12,418	22.4%	N/A	22.4%	N/A						
7	Perdido												
8	Gas		2,123				9,902	21,021	1,000,000	21,021	101,625	4.79	4.83
9	Plant Unit Info	4.0	2,123	71.4%	100.0%	71.4%	9,902			21,021	101,625	4.79	
10	Pioneer Trail PV Solar												
11	Solar		13,603					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	13,603	24.5%	N/A	24.5%	N/A						
13	Riviera 5												
14	Gas		525,338				6,703	3,521,494	1,000,000	3,521,494	17,280,305	3.29	4.91
15	Plant Unit Info	1,308.0	525,338	54.0%	93.4%	57.8%	6,703			3,521,494	17,280,305	3.29	
16	Rodeo PV Solar												
17	Solar		12,810					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	12,810	23.1%	N/A	23.1%	N/A						
19	Sabal Palm PV Solar												
20	Solar		12,698					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,698	22.9%	N/A	22.9%	N/A						
22	Sanford 4												
23	Gas		362,480				6,961	2,523,053	1,000,000	2,523,053	12,520,458	3.45	4.96
24	Plant Unit Info	1,147.0	362,480	42.5%	94.1%	45.2%	6,961			2,523,053	12,520,458	3.45	
25	Sanford 5												
26	Gas		469,773				6,961	3,270,099	1,000,000	3,270,099	16,219,786	3.45	4.96
27	Plant Unit Info	1,147.0	469,773	55.1%	94.1%	58.5%	6,961			3,270,099	16,219,786	3.45	
28	Sawgrass PV Solar												
29	Solar		13,581					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	13,581	24.5%	N/A	24.5%	N/A						
31	Scherer 3												
32	Coal		18,722				11,163	12,293	17,000,001	208,989	542,618	2.90	44.14
33	Plant Unit Info	215.0	18,722	11.7%	93.7%	12.5%	11,163			208,989	542,618	2.90	
34	Scherer 4												
35	Coal											N/A	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		267,173				7,060	1,886,130	1,000,000	1,886,130	9,414,233	3.52	4.99
4	Plant Unit Info	652.0	267,173	55.1%	93.9%	58.7%	7,060			1,886,130	9,414,233	3.52	
5	Smith A												
6	Plant Unit Info	32.0	0	N/A	93.8%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		16,729					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	16,729	30.2%	N/A	30.2%	N/A						
10	Space Coast												
11	Solar		1,451					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,451	19.5%	100.0%	19.5%	N/A						
13	St Lucie 1												
14	Nuclear		665,677				10,560	7,029,482	1,000,000	7,029,482	3,092,269	0.46	0.44
15	Plant Unit Info	981.0	665,677	91.1%	91.0%	100.0%	10,560			7,029,482	3,092,269	0.46	
16	St Lucie 2												
17	Nuclear		609,292				10,496	6,394,944	1,000,000	6,394,944	2,731,920	0.45	0.43
18	Plant Unit Info	840.0	609,292	97.5%	97.5%	100.0%	10,496			6,394,944	2,731,920	0.45	
19	Sundew PV Solar												
20	Solar		13,273					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,273	24.0%	N/A	24.0%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		14,347					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	14,347	25.9%	N/A	25.9%	N/A						
25	Sweetbay PV Solar												
26	Solar		13,027					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	13,027	23.5%	N/A	23.5%	N/A						
28	Trailside PV Solar												
29	Solar		11,968					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	11,968	21.6%	N/A	21.6%	N/A						
31	Turkey Point 3												
32	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,258,732	0.54	0.50
33	Plant Unit Info	837.0	607,178	97.5%	97.5%	100.0%	10,818			6,568,699	3,258,732	0.54	
34	Turkey Point 4												
35	Nuclear		612,238				10,729	6,568,514	1,000,000	6,568,514	3,466,205	0.57	0.53

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	844.0	612,238	97.5%	97.3%	100.0%	10,729			6,568,514	3,466,205	0.57	
2	Turkey Point 5												
3	Gas		531,659				6,868	3,651,418	1,000,000	3,651,418	17,739,847	3.34	4.86
4	Plant Unit Info	1,256.0	531,659	56.9%	93.9%	60.6%	6,868			3,651,418	17,739,847	3.34	
5	Twin Lakes ST Solar												
6	Solar		13,886					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,886	25.1%	N/A	25.1%	N/A						
8	Union Springs PV Solar												
9	Solar		12,397					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,397	22.4%	N/A	22.4%	N/A						
11	WCEC 01												
12	Gas		352,426				6,828	2,406,447	1,000,000	2,406,447	11,469,030	3.25	4.77
13	Plant Unit Info	1,223.0	352,426	38.7%	60.4%	64.1%	6,828			2,406,447	11,469,030	3.25	
14	WCEC 02												
15	Gas		673,384				6,679	4,497,783	1,000,000	4,497,783	21,434,484	3.18	4.77
16	Plant Unit Info	1,223.0	673,384	74.0%	93.2%	79.0%	6,679			4,497,783	21,434,484	3.18	
17	WCEC 03												
18	Gas		571,204				6,761	3,862,162	1,000,000	3,862,162	18,407,554	3.22	4.77
19	Plant Unit Info	1,228.0	571,204	62.5%	93.7%	66.7%	6,761			3,862,162	18,407,554	3.22	
20	Wildflower PV Solar												
21	Solar		15,474					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	15,474	27.9%	N/A	27.9%	N/A						
23	Willow PV Solar												
24	Solar		12,979					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	12,979	23.4%	N/A	23.4%	N/A						
26	System Totals												
27	Plant Unit Info	31,339	11,371,362				7,235			82,271,991	283,308,095	2.49	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Nov - 2022												
2	Babcock Preserve ST Solar												
3	Solar		13,755					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,755	25.6%	N/A	25.6%	N/A						
5	Babcock PV Solar												
6	Solar		12,647					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,647	23.6%	N/A	23.6%	N/A						
8	Barefoot PV Solar												
9	Solar		12,750					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,750	23.8%	N/A	23.8%	N/A						
11	Blue Cypress PV Solar												
12	Solar		13,101					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,101	24.4%	N/A	24.4%	N/A						
14	Blue Heron ST Solar												
15	Solar		13,755					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,755	25.6%	N/A	25.6%	N/A						
17	Blue Indigo PV Solar												
18	Solar		12,516					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	12,516	23.3%	N/A	23.3%	N/A						
20	Blue Springs PV Solar												
21	Solar		9,729					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	9,729	18.1%	N/A	18.1%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		12,159					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	12,159	22.7%	N/A	22.7%	N/A						
26	CCEC 3												
27	Gas		402,342				6,695	2,693,745	1,000,000	2,693,745	14,132,870	3.51	5.25
28	Plant Unit Info	1,326.0	402,342	42.1%	93.4%	45.1%	6,695			2,693,745	14,132,870	3.51	
29	Citrus PV Solar												
30	Solar		12,570					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	12,570	23.4%	N/A	23.4%	N/A						
32	Coral Farms PV Solar												
33	Solar		13,212					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	13,212	24.6%	N/A	24.6%	N/A						
35	Cotton Creek PV Solar												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		10,092					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	10,092	18.8%	N/A	18.8%	N/A						
3	Dania Beach												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		692,881				6,315	4,375,442	1,000,000	4,375,442	22,805,196	3.29	5.21
6	Plant Unit Info	1,190.0	692,881	80.9%	94.5%	86.2%	6,315			4,375,442	22,805,196	3.29	
7	Daniel 1												
8	Coal											N/A	0.00
9	Plant Unit Info	251.0	0	N/A	43.6%	N/A	N/A						
10	Daniel 2												
11	Coal											N/A	0.00
12	Plant Unit Info	251.0	0	N/A	93.6%	N/A	N/A						
13	Desoto Solar												
14	Solar		3,261					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	3,261	18.1%	N/A	18.1%	N/A						
16	Discovery PV Solar												
17	Solar		10,194					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	10,194	19.0%	N/A	19.0%	N/A						
19	Echo River PV Solar												
20	Solar		13,329					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,329	24.9%	N/A	24.9%	N/A						
22	Egret PV Solar												
23	Solar		9,806					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	9,806	18.3%	N/A	18.3%	N/A						
25	Elder Branch PV Solar												
26	Solar		13,223					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	13,223	24.7%	N/A	24.7%	N/A						
28	Fort Drum PV Solar												
29	Solar		9,979					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	9,979	18.6%	N/A	18.6%	N/A						
31	Fort Myers 2												
32	Gas		724,707				7,024	5,090,239	1,000,000	5,090,239	26,707,015	3.69	5.25
33	Plant Unit Info	1,740.0	724,707	57.9%	88.8%	65.2%	7,024			5,090,239	26,707,015	3.69	
34	Fort Myers 3A												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		<u>1,716</u>				10,930	18,756	1,000,000	<u>18,756</u>	<u>98,421</u>	<u>5.74</u>	5.25
2	Plant Unit Info	189.0	1,716	1.3%	93.8%	1.3%	10,930			18,756	98,421	5.74	
3	Fort Myers 3B												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		<u>0</u>					0	0	<u>0</u>	<u>0</u>	<u>0.00</u>	0.00
6	Plant Unit Info	193.0	0	N/A	93.8%	N/A	N/A						
7	Fort Myers 3C												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		<u>0</u>					0	0	<u>0</u>	<u>0</u>	<u>0.00</u>	0.00
10	Plant Unit Info	221.0	0	N/A	93.8%	N/A	N/A						
11	Fort Myers 3D												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		<u>0</u>					0	0	<u>0</u>	<u>0</u>	<u>0.00</u>	0.00
14	Plant Unit Info	221.0	0	N/A	93.8%	N/A	N/A						
15	GCEC 4												
16	Gas		<u>0</u>					0	0	<u>0</u>	<u>0</u>	<u>0.00</u>	0.00
17	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
18	GCEC 5												
19	Gas		<u>0</u>					0	0	<u>0</u>	<u>0</u>	<u>0.00</u>	0.00
20	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
21	GCEC 6												
22	Gas		<u>0</u>					0	0	<u>0</u>	<u>0</u>	<u>0.00</u>	0.00
23	Plant Unit Info	315.0	0	N/A	93.6%	N/A	N/A						
24	GCEC 7												
25	Gas		<u>0</u>					0	0	<u>0</u>	<u>0</u>	<u>0.00</u>	0.00
26	Plant Unit Info	496.0	0	N/A	93.6%	N/A	N/A						
27	GCEC 8A												
28	Gas		<u>1,017</u>				10,580	10,756	1,000,000	<u>10,756</u>	<u>56,688</u>	<u>5.58</u>	5.27
29	Plant Unit Info	234.5	1,017	0.6%	93.8%	0.7%	10,580			10,756	56,688	5.58	
30	GCEC 8B												
31	Gas		<u>3,188</u>				10,396	33,146	1,000,000	<u>33,146</u>	<u>174,856</u>	<u>5.48</u>	5.28
32	Plant Unit Info	235.0	3,188	1.9%	93.8%	2.1%	10,396			33,146	174,856	5.48	
33	GCEC 8C												
34	Gas		<u>1,923</u>				10,823	20,808	1,000,000	<u>20,808</u>	<u>109,771</u>	<u>5.71</u>	5.28
35	Plant Unit Info	234.5	1,923	1.2%	93.8%	1.3%	10,823			20,808	109,771	5.71	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		1,652				11,551	19,083	1,000,000	19,083	100,816	6.10	5.28
3	Plant Unit Info	234.5	1,652	1.0%	93.8%	1.1%	11,551			19,083	100,816	6.10	
4	Ghost Orchid PV Solar												
5	Solar		12,256					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	12,256	22.9%	N/A	22.9%	N/A						
7	Grove PV Solar												
8	Solar		11,621					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	11,621	21.7%	N/A	21.7%	N/A						
10	Hammock PV Solar												
11	Solar		14,053					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	14,053	26.2%	N/A	26.2%	N/A						
13	Hibiscus PV Solar												
14	Solar		12,211					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	12,211	22.8%	N/A	22.8%	N/A						
16	Horizon PV Solar												
17	Solar		13,335					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	13,335	24.9%	N/A	24.9%	N/A						
19	Immokalee PV Solar												
20	Solar		12,606					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,606	23.5%	N/A	23.5%	N/A						
22	Indian River PV Solar												
23	Solar		13,089					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	13,089	24.4%	N/A	24.4%	N/A						
25	Interstate PV Solar												
26	Solar		12,422					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	12,422	23.2%	N/A	23.2%	N/A						
28	Lakeside PV Solar												
29	Solar		11,171					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	11,171	20.8%	N/A	20.8%	N/A						
31	Lauderdale 6A												
32	Gas		1,013				10,585	10,723	1,000,000	10,723	55,856	5.51	5.21
33	Plant Unit Info	218.0	1,013	0.7%	94.0%	0.7%	10,585			10,723	55,856	5.51	
34	Lauderdale 6B												
35	Gas		1,013				10,585	10,723	1,000,000	10,723	55,856	5.51	5.21

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	218.0	1,013	0.7%	94.0%	0.7%	10,585			10,723	55,856	5.51	
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		1,013				10,585	10,723	1,000,000	10,723	55,856	5.51	5.21
5	Plant Unit Info	218.0	1,013	0.7%	94.0%	0.7%	10,585			10,723	55,856	5.51	
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		1,013				10,585	10,723	1,000,000	10,723	55,856	5.51	5.21
9	Plant Unit Info	218.0	1,013	0.7%	94.0%	0.7%	10,585			10,723	55,856	5.51	
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
14	Loggerhead PV Solar												
15	Solar		13,286					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,286	24.8%	N/A	24.8%	N/A						
17	Magnolia PV Solar												
18	Solar		9,787					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	9,787	18.2%	N/A	18.2%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		620,219				6,795	4,214,584	1,000,000	4,214,584	21,831,125	3.52	5.18
30	Plant Unit Info	1,303.0	620,219	65.3%	91.4%	71.4%	6,795			4,214,584	21,831,125	3.52	
31	Manatee PV Solar												
32	Solar		12,714					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	12,714	23.7%	N/A	23.7%	N/A						
34	Martin 3												
35	Gas		0					0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	492.0	0	N/A	N/A	N/A	N/A						
2	Martin 4												
3	Gas		26,574				7,762	206,272	1,000,000	206,272	1,070,784	4.03	5.19
4	Plant Unit Info	492.0	26,574	7.5%	93.9%	8.0%	7,762			206,272	1,070,784	4.03	
5	Martin 8												
6	Gas		420,753				6,931	2,916,387	1,000,000	2,916,387	15,104,936	3.59	5.18
7	Plant Unit Info	1,264.0	420,753	46.1%	80.2%	57.5%	6,931			2,916,387	15,104,936	3.59	
8	Martin 8 Solar												
9	Solar		6,510					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	6,510	16.4%	N/A	16.4%	N/A						
11	Miami-Dade PV Solar												
12	Solar		13,058					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,058	24.3%	N/A	24.3%	N/A						
14	Nassau PV Solar												
15	Solar		9,442					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	9,442	17.6%	N/A	17.6%	N/A						
17	Northern Preserve ST Solar												
18	Solar		11,955					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	11,955	22.3%	N/A	22.3%	N/A						
20	OKEECHOBEE 1												
21	Gas		743,201				6,346	4,716,587	1,000,000	4,716,587	24,870,666	3.35	5.27
22	Plant Unit Info	1,640.0	743,201	62.9%	76.3%	82.5%	6,346			4,716,587	24,870,666	3.35	
23	Okeechobee PV Solar												
24	Solar		12,724					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	12,724	23.7%	N/A	23.7%	N/A						
26	Orange Blossom PV Solar												
27	Solar		10,986					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	10,986	20.5%	N/A	20.5%	N/A						
29	Palm Bay PV Solar												
30	Solar		10,818					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	10,818	20.2%	N/A	20.2%	N/A						
32	Pea Ridge												
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	15.0	0	N/A	93.7%	N/A	N/A						
35	PEEC												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		469,333				6,362	2,986,131	1,000,000	2,986,131	15,568,023	3.32	5.21
3	Plant Unit Info	1,283.0	469,333	49.7%	49.6%	100.0%	6,362			2,986,131	15,568,023	3.32	
4	Pelican PV Solar												
5	Solar		10,986					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	10,986	20.5%	N/A	20.5%	N/A						
7	Perdido												
8	Gas		2,055				9,899	20,343	1,000,000	20,343	104,222	5.07	5.12
9	Plant Unit Info	4.0	2,055	71.4%	100.0%	71.4%	9,899			20,343	104,222	5.07	
10	Pioneer Trail PV Solar												
11	Solar		12,082					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	12,082	22.5%	N/A	22.5%	N/A						
13	Riviera 5												
14	Gas		473,103				6,670	3,155,455	1,000,000	3,155,455	16,638,784	3.52	5.27
15	Plant Unit Info	1,326.0	473,103	49.6%	93.4%	53.0%	6,670			3,155,455	16,638,784	3.52	
16	Rodeo PV Solar												
17	Solar		10,751					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	10,751	20.0%	N/A	20.0%	N/A						
19	Sabal Palm PV Solar												
20	Solar		11,292					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	11,292	21.1%	N/A	21.1%	N/A						
22	Sanford 4												
23	Gas		70,642				7,315	516,721	1,000,000	516,721	2,716,102	3.84	5.26
24	Plant Unit Info	1,192.0	70,642	8.2%	91.6%	9.0%	7,315			516,721	2,716,102	3.84	
25	Sanford 5												
26	Gas		398,100				6,961	2,771,344	1,000,000	2,771,344	14,542,832	3.65	5.25
27	Plant Unit Info	1,192.0	398,100	46.4%	94.1%	49.3%	6,961			2,771,344	14,542,832	3.65	
28	Sawgrass PV Solar												
29	Solar		12,204					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	12,204	22.8%	N/A	22.8%	N/A						
31	Scherer 3												
32	Coal											N/A	0.00
33	Plant Unit Info	215.0	0	N/A	93.7%	N/A	N/A						
34	Scherer 4												
35	Coal											N/A	0.00

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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		106,626				7,056	752,387	1,000,000	752,387	3,988,120	3.74	5.30
4	Plant Unit Info	632.0	106,626	23.4%	93.9%	25.0%	7,056			752,387	3,988,120	3.74	
5	Smith A												
6	Plant Unit Info	40.0	0	N/A	93.8%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		14,045					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	14,045	26.2%	N/A	26.2%	N/A						
10	Space Coast												
11	Solar		1,255					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,255	17.4%	100.0%	17.4%	N/A						
13	St Lucie 1												
14	Nuclear		704,121				10,328	7,272,374	1,000,000	7,272,374	3,199,118	0.45	0.44
15	Plant Unit Info	1,003.0	704,121	97.5%	97.3%	100.0%	10,328			7,272,374	3,199,118	0.45	
16	St Lucie 2												
17	Nuclear		603,399				10,257	6,188,882	1,000,000	6,188,882	2,643,891	0.44	0.43
18	Plant Unit Info	859.6	603,399	97.5%	97.5%	100.0%	10,257			6,188,882	2,643,891	0.44	
19	Sundew PV Solar												
20	Solar		11,671					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	11,671	21.8%	N/A	21.8%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		12,701					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	12,701	23.7%	N/A	23.7%	N/A						
25	Sweetbay PV Solar												
26	Solar		11,706					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	11,706	21.8%	N/A	21.8%	N/A						
28	Trailside PV Solar												
29	Solar		9,753					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	9,753	18.2%	N/A	18.2%	N/A						
31	Turkey Point 3												
32	Nuclear		603,000				10,541	6,356,404	1,000,000	6,356,404	3,153,412	0.52	0.50
33	Plant Unit Info	859.0	603,000	97.5%	97.5%	100.0%	10,541			6,356,404	3,153,412	0.52	
34	Turkey Point 4												
35	Nuclear		607,968				10,456	6,356,974	1,000,000	6,356,974	3,354,575	0.55	0.53

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	866.0	607,968	97.5%	97.3%	100.0%	10,456			6,356,974	3,354,575	0.55	
2	Turkey Point 5												
3	Gas		269,135				6,900	1,857,084	1,000,000	1,857,084	9,679,699	3.60	5.21
4	Plant Unit Info	1,294.0	269,135	28.9%	93.9%	30.8%	6,900			1,857,084	9,679,699	3.60	
5	Twin Lakes ST Solar												
6	Solar		11,832					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	11,832	22.1%	N/A	22.1%	N/A						
8	Union Springs PV Solar												
9	Solar		9,899					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	9,899	18.5%	N/A	18.5%	N/A						
11	WCEC 01												
12	Gas		87,881				6,856	602,492	1,000,000	602,492	3,118,927	3.55	5.18
13	Plant Unit Info	1,248.0	87,881	9.8%	60.4%	16.2%	6,856			602,492	3,118,927	3.55	
14	WCEC 02												
15	Gas		556,237				6,716	3,735,523	1,000,000	3,735,523	19,349,167	3.48	5.18
16	Plant Unit Info	1,248.0	556,237	61.9%	93.2%	66.1%	6,716			3,735,523	19,349,167	3.48	
17	WCEC 03												
18	Gas		444,532				6,735	2,993,739	1,000,000	2,993,739	15,497,721	3.49	5.18
19	Plant Unit Info	1,254.0	444,532	49.2%	80.4%	61.2%	6,735			2,993,739	15,497,721	3.49	
20	Wildflower PV Solar												
21	Solar		13,864					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	13,864	25.9%	N/A	25.9%	N/A						
23	Willow PV Solar												
24	Solar		11,131					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	11,131	20.8%	N/A	20.8%	N/A						
26	System Totals												
27	Plant Unit Info	31,965	9,625,651				7,264			69,924,550	240,841,160	2.50	N/A
28													
29													
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Dec - 2022												
2	Babcock Preserve ST Solar												
3	Solar		12,564					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,564	22.7%	N/A	22.7%	N/A						
5	Babcock PV Solar												
6	Solar		11,786					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	11,786	21.3%	N/A	21.3%	N/A						
8	Barefoot PV Solar												
9	Solar		11,620					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	11,620	21.0%	N/A	21.0%	N/A						
11	Blue Cypress PV Solar												
12	Solar		12,043					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,043	21.7%	N/A	21.7%	N/A						
14	Blue Heron ST Solar												
15	Solar		12,564					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,564	22.7%	N/A	22.7%	N/A						
17	Blue Indigo PV Solar												
18	Solar		9,900					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	9,900	17.9%	N/A	17.9%	N/A						
20	Blue Springs PV Solar												
21	Solar		7,697					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	7,697	13.9%	N/A	13.9%	N/A						
23	Cattle Ranch ST Solar												
24	Solar		10,595					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	10,595	19.1%	N/A	19.1%	N/A						
26	CCEC 3												
27	Gas		373,987				6,721	2,513,433	1,000,000	2,513,433	13,612,076	3.64	5.42
28	Plant Unit Info	1,326.0	373,987	37.9%	93.4%	40.6%	6,721			2,513,433	13,612,076	3.64	
29	Citrus PV Solar												
30	Solar		11,757					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	11,757	21.2%	N/A	21.2%	N/A						
32	Coral Farms PV Solar												
33	Solar		12,061					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	74.5	12,061	21.8%	N/A	21.8%	N/A						
35	Cotton Creek PV Solar												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		8,197					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	8,197	14.8%	N/A	14.8%	N/A						
3	Dania Beach												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		624,967				6,331	3,956,389	1,000,000	3,956,389	21,319,187	3.41	5.39
6	Plant Unit Info	1,190.0	624,967	70.6%	94.5%	75.3%	6,331			3,956,389	21,319,187	3.41	
7	Daniel 1												
8	Coal											N/A	0.00
9	Plant Unit Info	251.0	0	N/A	93.6%	N/A	N/A						
10	Daniel 2												
11	Coal											N/A	0.00
12	Plant Unit Info	251.0	0	N/A	93.6%	N/A	N/A						
13	Desoto Solar												
14	Solar		2,906					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	25.0	2,906	15.6%	N/A	15.6%	N/A						
16	Discovery PV Solar												
17	Solar		9,342					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	9,342	16.9%	N/A	16.9%	N/A						
19	Echo River PV Solar												
20	Solar		10,814					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	10,814	19.5%	N/A	19.5%	N/A						
22	Egret PV Solar												
23	Solar		8,172					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	8,172	14.7%	N/A	14.7%	N/A						
25	Elder Branch PV Solar												
26	Solar		11,352					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	11,352	20.5%	N/A	20.5%	N/A						
28	Fort Drum PV Solar												
29	Solar		9,111					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	9,111	16.4%	N/A	16.4%	N/A						
31	Fort Myers 2												
32	Gas		735,754				7,008	5,155,882	1,000,000	5,155,882	27,916,174	3.79	5.41
33	Plant Unit Info	1,740.0	735,754	56.8%	79.8%	71.2%	7,008			5,155,882	27,916,174	3.79	
34	Fort Myers 3A												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
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SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	189.0	0	N/A	93.8%	N/A	N/A						
3	Fort Myers 3B												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	193.0	0	N/A	93.8%	N/A	N/A						
7	Fort Myers 3C												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	221.0	0	N/A	93.8%	N/A	N/A						
11	Fort Myers 3D												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		908				11,128	10,104	1,000,000	10,104	54,448	6.00	5.39
14	Plant Unit Info	221.0	908	0.6%	93.8%	0.6%	11,128			10,104	54,448	6.00	
15	GCEC 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
18	GCEC 5												
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	78.0	0	N/A	93.6%	N/A	N/A						
21	GCEC 6												
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	315.0	0	N/A	93.6%	N/A	N/A						
24	GCEC 7												
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	496.0	0	N/A	93.6%	N/A	N/A						
27	GCEC 8A												
28	Gas		0					0	0	0	0	0.00	0.00
29	Plant Unit Info	234.5	0	N/A	93.8%	N/A	N/A						
30	GCEC 8B												
31	Gas		1,754				11,251	19,731	1,000,000	19,731	107,737	6.14	5.46
32	Plant Unit Info	235.0	1,754	1.0%	93.8%	1.1%	11,251			19,731	107,737	6.14	
33	GCEC 8C												
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	234.5	0	N/A	93.8%	N/A	N/A						

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	GCEC 8D												
2	Gas		464				13,796	6,405	1,000,000	6,405	34,974	7.53	5.46
3	Plant Unit Info	234.5	464	0.3%	93.8%	0.3%	13,796			6,405	34,974	7.53	
4	Ghost Orchid PV Solar												
5	Solar		11,487					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	11,487	20.7%	N/A	20.7%	N/A						
7	Grove PV Solar												
8	Solar		10,856					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	10,856	19.6%	N/A	19.6%	N/A						
10	Hammock PV Solar												
11	Solar		12,892					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	12,892	23.3%	N/A	23.3%	N/A						
13	Hibiscus PV Solar												
14	Solar		11,247					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	74.5	11,247	20.3%	N/A	20.3%	N/A						
16	Horizon PV Solar												
17	Solar		12,148					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	12,148	21.9%	N/A	21.9%	N/A						
19	Immokalee PV Solar												
20	Solar		11,636					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	11,636	21.0%	N/A	21.0%	N/A						
22	Indian River PV Solar												
23	Solar		12,031					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	12,031	21.7%	N/A	21.7%	N/A						
25	Interstate PV Solar												
26	Solar		11,611					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	11,611	21.0%	N/A	21.0%	N/A						
28	Lakeside PV Solar												
29	Solar		10,447					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	10,447	18.9%	N/A	18.9%	N/A						
31	Lauderdale 6A												
32	Gas		0					0	0	0	0	0.00	0.00
33	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
34	Lauderdale 6B												
35	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
2	Lauderdale 6C												
3	Light Oil		0				0	0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
6	Lauderdale 6D												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
10	Lauderdale 6E												
11	Light Oil		0				0	0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
14	Loggerhead PV Solar												
15	Solar		12,343					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,343	22.3%	N/A	22.3%	N/A						
17	Magnolia PV Solar												
18	Solar		8,228					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	8,228	14.8%	N/A	14.8%	N/A						
20	Manatee 1												
21	Heavy Oil											N/A	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
24	Manatee 2												
25	Heavy Oil											N/A	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
28	Manatee 3												
29	Gas		620,596				6,810	4,226,528	1,000,000	4,226,528	22,639,811	3.65	5.36
30	Plant Unit Info	1,303.0	620,596	63.2%	93.9%	67.3%	6,810			4,226,528	22,639,811	3.65	
31	Manatee PV Solar												
32	Solar		11,751					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	74.5	11,751	21.2%	N/A	21.2%	N/A						
34	Martin 3												
35	Gas		97,977				7,397	724,759	1,000,000	724,759	3,882,244	3.96	5.36

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	492.0	97,977	26.8%	51.4%	51.5%	7,397			724,759	3,882,244	3.96	
2	Martin 4												
3	Gas		13,128				8,587	112,736	1,000,000	112,736	603,881	4.60	5.36
4	Plant Unit Info	492.0	13,128	3.6%	93.9%	3.8%	8,587			112,736	603,881	4.60	
5	Martin 8												
6	Gas		304,178				7,055	2,145,894	1,000,000	2,145,894	11,494,690	3.78	5.36
7	Plant Unit Info	1,269.0	304,178	32.0%	84.6%	37.9%	7,055			2,145,894	11,494,690	3.78	
8	Martin 8 Solar												
9	Solar		5,425					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	55.0	5,425	13.3%	N/A	13.3%	N/A						
11	Miami-Dade PV Solar												
12	Solar		12,413					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,413	22.4%	N/A	22.4%	N/A						
14	Nassau PV Solar												
15	Solar		7,747					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	7,747	14.0%	N/A	14.0%	N/A						
17	Northern Preserve ST Solar												
18	Solar		10,920					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	10,920	19.7%	N/A	19.7%	N/A						
20	OKEECHOBEE 1												
21	Gas		830,766				6,360	5,283,996	1,000,000	5,283,996	28,731,110	3.46	5.44
22	Plant Unit Info	1,640.0	830,766	68.1%	93.0%	73.2%	6,360			5,283,996	28,731,110	3.46	
23	Okeechobee PV Solar												
24	Solar		11,539					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	11,539	20.8%	N/A	20.8%	N/A						
26	Orange Blossom PV Solar												
27	Solar		10,031					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	10,031	18.1%	N/A	18.1%	N/A						
29	Palm Bay PV Solar												
30	Solar		9,871					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	74.5	9,871	17.8%	N/A	17.8%	N/A						
32	Pea Ridge												
33	Gas		28				15,000	420	1,000,000	420	2,294	8.19	5.46
34	Plant Unit Info	15.0	28	0.3%	93.7%	0.3%	15,000			420	2,294	8.19	
35	PEEC												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		649,596				6,425	4,173,409	1,000,000	4,173,409	22,488,611	3.46	5.39
3	Plant Unit Info	1,283.0	649,596	68.1%	93.0%	73.2%	6,425			4,173,409	22,488,611	3.46	
4	Pelican PV Solar												
5	Solar		10,031					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	10,031	18.1%	N/A	18.1%	N/A						
7	Perdido												
8	Gas		2,123				9,902	21,021	1,000,000	21,021	108,556	5.11	5.16
9	Plant Unit Info	4.0	2,123	71.4%	100.0%	71.4%	9,902			21,021	108,556	5.11	
10	Pioneer Trail PV Solar												
11	Solar		11,197					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	74.5	11,197	20.2%	N/A	20.2%	N/A						
13	Riviera 5												
14	Gas		435,865				6,700	2,920,090	1,000,000	2,920,090	15,877,647	3.64	5.44
15	Plant Unit Info	1,326.0	435,865	44.2%	93.4%	47.3%	6,700			2,920,090	15,877,647	3.64	
16	Rodeo PV Solar												
17	Solar		9,474					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	9,474	17.1%	N/A	17.1%	N/A						
19	Sabal Palm PV Solar												
20	Solar		10,439					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	10,439	18.8%	N/A	18.8%	N/A						
22	Sanford 4												
23	Gas		65,345				7,451	486,901	1,000,000	486,901	2,637,743	4.04	5.42
24	Plant Unit Info	1,192.0	65,345	7.4%	78.0%	9.5%	7,451			486,901	2,637,743	4.04	
25	Sanford 5												
26	Gas		413,350				6,977	2,883,901	1,000,000	2,883,901	15,616,228	3.78	5.41
27	Plant Unit Info	1,192.0	413,350	46.6%	94.1%	49.5%	6,977			2,883,901	15,616,228	3.78	
28	Sawgrass PV Solar												
29	Solar		11,409					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	11,409	20.6%	N/A	20.6%	N/A						
31	Scherer 3												
32	Coal											N/A	0.00
33	Plant Unit Info	215.0	0	N/A	93.7%	N/A	N/A						
34	Scherer 4												
35	Coal											N/A	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Smith 3												
3	Gas		31,432				7,154	224,879	1,000,000	224,879	1,227,904	3.91	5.46
4	Plant Unit Info	632.0	31,432	6.7%	93.9%	7.1%	7,154			224,879	1,227,904	3.91	
5	Smith A												
6	Plant Unit Info	40.0	0	N/A	93.8%	N/A	N/A						
7	Southfork PV Solar												
8	Solar		12,295					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	74.5	12,295	22.2%	N/A	22.2%	N/A						
10	Space Coast												
11	Solar		1,170					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	10.0	1,170	15.7%	100.0%	15.7%	N/A						
13	St Lucie 1												
14	Nuclear		727,591				10,328	7,514,787	1,000,000	7,514,787	3,305,755	0.45	0.44
15	Plant Unit Info	1,003.0	727,591	97.5%	97.3%	100.0%	10,328			7,514,787	3,305,755	0.45	
16	St Lucie 2												
17	Nuclear		623,512				10,257	6,395,178	1,000,000	6,395,178	2,732,020	0.44	0.43
18	Plant Unit Info	859.6	623,512	97.5%	97.5%	100.0%	10,257			6,395,178	2,732,020	0.44	
19	Sundew PV Solar												
20	Solar		11,049					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	11,049	19.9%	N/A	19.9%	N/A						
22	Sunshine Gateway PV Solar												
23	Solar		10,864					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	74.5	10,864	19.6%	N/A	19.6%	N/A						
25	Sweetbay PV Solar												
26	Solar		10,858					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	10,858	19.6%	N/A	19.6%	N/A						
28	Trailside PV Solar												
29	Solar		8,552					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	8,552	15.4%	N/A	15.4%	N/A						
31	Turkey Point 3												
32	Nuclear		623,100				10,541	6,568,284	1,000,000	6,568,284	3,258,526	0.52	0.50
33	Plant Unit Info	859.0	623,100	97.5%	97.5%	100.0%	10,541			6,568,284	3,258,526	0.52	
34	Turkey Point 4												
35	Nuclear		628,234				10,456	6,568,874	1,000,000	6,568,874	3,466,395	0.55	0.53

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	866.0	628,234	97.5%	97.3%	100.0%	10,456			6,568,874	3,466,395	0.55	
2	Turkey Point 5												
3	Gas		354,755				6,964	2,470,415	1,000,000	2,470,415	13,311,949	3.75	5.39
4	Plant Unit Info	1,294.0	354,755	36.9%	71.4%	51.6%	6,964			2,470,415	13,311,949	3.75	
5	Twin Lakes ST Solar												
6	Solar		10,310					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	10,310	18.6%	N/A	18.6%	N/A						
8	Union Springs PV Solar												
9	Solar		8,322					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	8,322	15.0%	N/A	15.0%	N/A						
11	WCEC 01												
12	Gas		100,463				6,881	691,262	1,000,000	691,262	3,702,811	3.69	5.36
13	Plant Unit Info	1,248.0	100,463	10.8%	69.0%	15.7%	6,881			691,262	3,702,811	3.69	
14	WCEC 02												
15	Gas		509,999				6,747	3,440,845	1,000,000	3,440,845	18,431,223	3.61	5.36
16	Plant Unit Info	1,248.0	509,999	54.9%	93.2%	58.6%	6,747			3,440,845	18,431,223	3.61	
17	WCEC 03												
18	Gas		355,771				6,805	2,420,844	1,000,000	2,420,844	12,967,487	3.64	5.36
19	Plant Unit Info	1,254.0	355,771	38.1%	74.4%	51.3%	6,805			2,420,844	12,967,487	3.64	
20	Wildflower PV Solar												
21	Solar		12,684					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	12,684	22.9%	N/A	22.9%	N/A						
23	Willow PV Solar												
24	Solar		9,726					N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	9,726	17.6%	N/A	17.6%	N/A						
26	System Totals												
27	Plant Unit Info	31,970	9,651,128				7,350			70,936,967	249,531,482	2.59	N/A
28													
29	Note: Totals may not add due to rounding.												
30													
31													
32													
33													
34													
35													

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
INVENTORY PROJECTION

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	2022
#6 Heavy Oil (BBLs)													
Purchases													
Units													
Unit Cost													
Amount													
Burned													
Units													
Unit Cost													
Amount													
Ending Inventory													
Units	475,820	475,820	475,820	475,820	475,820	475,820	475,820	475,820	475,820	475,820	475,820	475,820	475,820
Unit Cost	74.8961	74.8961	74.8961	74.8961	74.8961	74.8961	74.8961	74.8961	74.8961	74.8961	74.8961	74.8961	74.8961
Amount	35,637,059	35,637,059	35,637,059	35,637,059	35,637,059	35,637,059	35,637,059	35,637,059	35,637,059	35,637,059	35,637,059	35,637,059	35,637,059
#2 Light Oil (BBLs)													
Purchases													
Units													
Unit Cost													
Amount													
Burned													
Units		203		3,239		10,905	1,962	1,001	245	3,891			21,445
Unit Cost		95.0445		95.0464		80.2983	84.9886	79.3632	79.3639	94.9569			85.6995
Amount		19,286		307,816		875,637	166,712	79,431	19,453	369,486			1,837,822
Ending Inventory													
Units	1,540,129	1,539,926	1,539,926	1,536,687	1,536,687	1,525,783	1,523,821	1,522,820	1,522,575	1,518,684	1,518,684	1,518,684	1,518,684
Unit Cost	92.6249	92.6245	92.6245	92.6194	92.6194	92.7075	92.7174	92.7262	92.7284	92.7227	92.7227	92.7227	92.7227
Amount	142,654,243	142,634,957	142,634,957	142,327,140	142,327,140	141,451,503	141,284,791	141,205,360	141,185,907	140,816,421	140,816,421	140,816,421	140,816,421
Coal													
Purchases													
Units	3,190,300	3,190,300	3,279,400	3,279,400	2,923,000	2,923,000	1,091,000	645,500	200,000	200,000	200,000	200,000	21,321,900
Unit Cost	2.6503	2.6370	2.6348	2.6477	2.6383	2.6345	2.8675	2.8321	2.6077	2.5992	2.6087	2.6183	2.6568
Amount	8,455,220	8,412,724	8,640,466	8,683,017	7,711,642	7,700,784	3,128,495	1,828,097	521,540	519,840	521,740	523,660	56,647,225
Burned													
Units	3,739,522	3,332,922	3,130,500	2,070,470	2,238,925	3,066,928			262,796	208,989			18,051,053
Unit Cost	2.6561	2.6415	2.6396	2.6494	2.6444	2.6361			2.5960	2.5964			2.6433
Amount	9,932,480	8,803,748	8,263,185	5,485,468	5,920,555	8,084,800			682,226	542,618			47,715,079
Ending Inventory													
Units	2,273,292	2,130,670	2,279,570	3,488,500	4,172,575	4,028,647	5,119,647	5,765,147	5,702,351	5,693,362	5,893,362	6,093,362	6,093,362
Unit Cost	2.6365	2.6294	2.6232	2.6307	2.6287	2.6273	2.6785	2.6957	2.6972	2.6974	2.6944	2.6919	2.6919
Amount	5,993,422	5,602,398	5,979,679	9,177,229	10,968,316	10,584,300	13,712,794	15,540,892	15,380,206	15,357,428	15,879,168	16,402,828	16,402,828
Gas (MMBTU)													
Burned													
Units	46,874,793	42,630,675	47,573,298	49,026,504	56,384,590	64,090,543	65,114,541	66,136,763	63,735,113	55,478,678	43,749,916	43,889,844	644,685,258
Unit Cost	5.9611	5.8756	5.6229	5.0219	4.7741	4.5734	4.6502	4.6428	4.6289	4.8640	5.2226	5.3946	5.0348
Amount	279,423,584	250,480,261	267,500,833	246,205,997	269,186,898	293,110,013	302,796,604	307,057,283	295,025,258	269,846,865	228,490,165	236,768,786	3,245,892,546
Nuclear (Other)													
Burned													
Units	27,047,123	24,429,659	22,809,140	24,266,978	27,046,432	26,173,966	27,046,432	27,046,432	19,386,880	26,561,639	26,174,634	27,047,123	305,036,436
Unit Cost	0.5004	0.5004	0.4834	0.4814	0.4848	0.4848	0.4848	0.4848	0.4842	0.4725	0.4719	0.4719	0.4837
Amount	13,535,074	12,225,228	11,025,340	11,681,793	13,111,049	12,688,111	13,111,049	13,111,049	9,387,551	12,549,126	12,350,995	12,762,696	147,539,060

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
POWER SOLD PURCHASED POWER

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Power Sold To / Purchased From	Type & Schedule	Total KWH Sold (000)	KWH from Own Generation (000)	Fuel Cost (cents/KWH)	Total Cost (cents/KWH)	Total \$ for Fuel Adj	Total Cost (\$)	Gain from Off System Sales (\$)
1	<u>Jan - 2022</u>								
2	Associated Interchange	IIC	393,805	393,805	2.974	2.974	11,712,949	11,712,949	
3	Off System	OS	330,331	330,331	2.676	4.087	8,840,796	13,499,520	3,840,601
4	St Lucie Reliability Sales	St. L.	54,191	54,191	0.519	0.519	281,110	281,110	
5	Subtotal Jan - 2022		778,326	778,326	2.677	3.275	20,834,855	25,493,579	3,840,601
6									
7	<u>Feb - 2022</u>								
8	Associated Interchange	IIC	300,938	300,938	2.577	2.577	7,755,735	7,755,735	
9	Off System	OS	351,740	351,740	2.670	3.866	9,390,739	13,597,073	3,306,164
10	St Lucie Reliability Sales	St. L.	48,947	48,947	0.519	0.519	253,905	253,905	
11	Subtotal Feb - 2022		701,624	701,624	2.480	3.080	17,400,379	21,606,714	3,306,164
12									
13	<u>Mar - 2022</u>								
14	Associated Interchange	IIC	530,085	530,085	2.354	2.354	12,477,971	12,477,971	
15	Off System	OS	225,643	225,643	2.575	3.537	5,809,197	7,981,530	1,639,047
16	St Lucie Reliability Sales	St. L.	54,191	54,191	0.519	0.519	281,110	281,110	
17	Subtotal Mar - 2022		809,919	809,919	2.293	2.561	18,568,277	20,740,610	1,639,047
18									
19	<u>Apr - 2022</u>								
20	Associated Interchange	IIC	563,239	563,239	2.210	2.210	12,447,004	12,447,004	
21	Off System	OS	221,075	221,075	2.453	3.515	5,422,496	7,770,446	1,869,543
22	St Lucie Reliability Sales	St. L.	51,287	51,287	0.542	0.542	278,123	278,123	
23	Subtotal Apr - 2022		835,601	835,601	2.172	2.453	18,147,622	20,495,572	1,869,543
24									
25	<u>May - 2022</u>								
26	Associated Interchange	IIC	400,663	400,663	2.344	2.344	9,389,964	9,389,964	
27	Off System	OS	190,167	190,167	2.169	3.298	4,124,213	6,272,567	1,762,340
28	St Lucie Reliability Sales	St. L.	52,997	52,997	0.542	0.542	287,393	287,393	
29	Subtotal May - 2022		643,827	643,827	2.144	2.477	13,801,570	15,949,925	1,762,340
30									

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
POWER SOLD PURCHASED POWER

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Power Sold To / Purchased From	Type & Schedule	Total KWH Sold (000)	KWH from Own Generation (000)	Fuel Cost (cents/KWH)	Total Cost (cents/KWH)	Total \$ for Fuel Adj	Total Cost (\$)	Gain from Off System Sales (\$)
31	<u>Jun - 2022</u>								
32	Associated Interchange	IIC	664,522	664,522	2.779	2.779	18,467,516	18,467,516	
33	Off System	OS	166,683	166,683	2.558	3.711	4,264,384	6,184,855	1,638,340
34	St Lucie Reliability Sales	St. L.	51,287	51,287	0.542	0.542	278,123	278,123	
35	Subtotal Jun - 2022		882,492	882,492	2.607	2.825	23,010,022	24,930,493	1,638,340
36									
37	<u>Jul - 2022</u>								
38	Off System	OS	132,680	132,680	2.352	3.554	3,120,370	4,715,768	1,388,351
39	St Lucie Reliability Sales	St. L.	52,997	52,997	0.542	0.542	287,393	287,393	
40	Subtotal Jul - 2022		185,677	185,677	1.835	2.695	3,407,763	5,003,161	1,388,351
41									
42	<u>Aug - 2022</u>								
43	Off System	OS	144,150	144,150	2.391	3.549	3,446,537	5,115,644	1,406,703
44	St Lucie Reliability Sales	St. L.	52,997	52,997	0.542	0.542	287,393	287,393	
45	Subtotal Aug - 2022		197,147	197,147	1.894	2.741	3,733,930	5,403,037	1,406,703
46									
47	<u>Sep - 2022</u>								
48	Off System	OS	128,400	128,400	2.396	3.592	3,075,840	4,612,768	1,297,544
49	St Lucie Reliability Sales	St. L.	3,419	3,419	0.542	0.542	18,541	18,541	
50	Subtotal Sep - 2022		131,819	131,819	2.347	3.513	3,094,381	4,631,309	1,297,544
51									
52	<u>Oct - 2022</u>								
53	Off System	OS	119,970	119,970	2.521	3.740	3,024,078	4,486,747	1,189,467
54	St Lucie Reliability Sales	St. L.	49,578	49,578	0.491	0.491	243,200	243,200	
55	Subtotal Oct - 2022		169,548	169,548	1.927	2.790	3,267,278	4,729,946	1,189,467
56									
57	<u>Nov - 2022</u>								
58	Off System	OS	218,100	218,100	2.213	3.245	4,826,034	7,077,137	1,726,103
59	St Lucie Reliability Sales	St. L.	52,443	52,443	0.469	0.469	246,085	246,085	
60	Subtotal Nov - 2022		270,543	270,543	1.875	2.707	5,072,119	7,323,222	1,726,103
61									

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
POWER SOLD PURCHASED POWER

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Power Sold To / Purchased From	Type & Schedule	Total KWH Sold (000)	KWH from Own Generation (000)	Fuel Cost (cents/KWH)	Total Cost (cents/KWH)	Total \$ for Fuel Adj	Total Cost (\$)	Gain from Off System Sales (\$)
62	<u>Dec - 2022</u>								
63	Off System	OS	205,530	205,530	2.254	3.350	4,632,045	6,885,094	1,640,732
64	St Lucie Reliability Sales	St. L.	54,191	54,191	0.469	0.469	254,288	254,288	
65	Subtotal Dec - 2022		259,721	259,721	1.881	2.749	4,886,333	7,139,382	1,640,732
66									
67	<u>2022</u>								
68	Associated Interchange	IIC	2,853,251	2,853,251	2.532	2.532	72,251,139	72,251,139	
69	Off System	OS	2,434,468	2,434,468	2.464	3.623	59,976,726	88,199,148	22,704,934
70	St Lucie Reliability Sales	St. L.	578,523	578,523	0.518	0.518	2,996,664	2,996,664	
71	Subtotal 2022		5,866,243	5,866,243	2.305	2.786	135,224,529	163,446,951	22,704,934
72									
73	Note: Totals may not add due to rounding.								

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Estimated Power Purchases	KWH Purchased (000)	KWH for Firm	Fuel Cost (cents/KWH)	Total \$ for Fuel Adj
1	<u>Jan - 2022</u>				
2	Central Alabama	240,433	240,433	3.815	9,172,395
3	King Fisher	71,424	71,424	4.503	3,215,924
4	St Lucie Reliability	54,566	54,566	0.449	245,236
5	SWA	83,693	83,693	3.612	3,022,710
6	Subtotal Jan - 2022	450,116	450,116	3.478	15,656,266
7					
8	<u>Feb - 2022</u>				
9	Central Alabama	198,087	198,087	3.813	7,553,347
10	King Fisher	49,700	49,700	4.401	2,187,394
11	St Lucie Reliability	49,286	49,286	0.449	221,503
12	SWA	79,249	79,249	3.691	2,924,827
13	Subtotal Feb - 2022	376,321	376,321	3.424	12,887,070
14					
15	<u>Mar - 2022</u>				
16	Central Alabama	446,763	446,763	3.310	14,787,708
17	King Fisher	104,284	104,284	4.578	4,773,692
18	St Lucie Reliability	54,566	54,566	0.449	245,236
19	SWA	78,671	78,671	3.644	2,866,810
20	Subtotal Mar - 2022	684,283	684,283	3.313	22,673,446
21					
22	<u>Apr - 2022</u>				
23	Central Alabama	140,598	140,598	3.573	5,023,127
24	King Fisher	112,230	112,230	4.589	5,150,182
25	St Lucie Reliability	51,598	51,598	0.471	242,830
26	SWA	78,595	78,595	3.323	2,611,881
27	Subtotal Apr - 2022	383,021	383,021	3.401	13,028,020
28					
29	<u>May - 2022</u>				
30	Central Alabama	445,567	445,567	2.900	12,919,940
31	King Fisher	79,205	79,205	4.526	3,584,466
32	St Lucie Reliability	53,318	53,318	0.471	250,924
33	SWA	71,424	71,424	3.123	2,230,561
34	Subtotal May - 2022	649,514	649,514	2.923	18,985,891
35					

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Estimated Power Purchases	KWH Purchased (000)	KWH for Firm	Fuel Cost (cents/KWH)	Total \$ for Fuel Adj
36	<u>Jun - 2022</u>				
37	Central Alabama	519,662	519,662	2.885	14,991,964
38	King Fisher	97,800	97,800	4.567	4,466,291
39	St Lucie Reliability	51,598	51,598	0.471	242,830
40	SWA	66,449	66,449	3.136	2,083,572
41	Subtotal Jun - 2022	735,509	735,509	2.962	21,784,657
42					
43	<u>Jul - 2022</u>				
44	Central Alabama	451,038	451,038	2.833	12,777,490
45	King Fisher	75,206	75,206	4.515	3,395,638
46	St Lucie Reliability	53,318	53,318	0.471	250,924
47	SWA	76,267	76,267	3.327	2,537,680
48	Subtotal Jul - 2022	655,830	655,830	2.891	18,961,732
49					
50	<u>Aug - 2022</u>				
51	Central Alabama	457,753	457,753	2.828	12,946,900
52	King Fisher	79,422	79,422	4.528	3,595,871
53	St Lucie Reliability	53,318	53,318	0.471	250,924
54	SWA	76,647	76,647	3.370	2,583,058
55	Subtotal Aug - 2022	667,140	667,140	2.904	19,376,752
56					
57	<u>Sep - 2022</u>				
58	Central Alabama	449,300	449,300	2.808	12,614,434
59	King Fisher	85,680	85,680	4.542	3,891,489
60	St Lucie Reliability	51,598	51,598	0.471	242,830
61	SWA	67,435	67,435	3.334	2,248,598
62	Subtotal Sep - 2022	654,013	654,013	2.905	18,997,350
63					
64	<u>Oct - 2022</u>				
65	Central Alabama	231,499	231,499	3.140	7,269,295
66	King Fisher	89,621	89,621	4.551	4,078,948
67	St Lucie Reliability	53,318	53,318	0.471	250,924
68	SWA	66,886	66,886	3.261	2,181,092
69	Subtotal Oct - 2022	441,324	441,324	3.122	13,780,258
70					

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Estimated Power Purchases	KWH Purchased (000)	KWH for Firm	Fuel Cost (cents/KWH)	Total \$ for Fuel Adj
71	<u>Nov - 2022</u>				
72	Central Alabama	380,729	380,729	2.952	11,240,974
73	King Fisher	111,750	111,750	4.589	5,127,805
74	St Lucie Reliability	52,806	52,806	0.449	237,325
75	SWA	68,429	68,429	3.583	2,451,563
76	Subtotal Nov - 2022	613,714	613,714	3.105	19,057,667
77					
78	<u>Dec - 2022</u>				
79	Central Alabama	411,347	411,347	3.023	12,434,714
80	King Fisher	74,958	74,958	4.513	3,383,186
81	St Lucie Reliability	54,566	54,566	0.449	245,236
82	SWA	79,236	79,236	3.340	2,646,197
83	Subtotal Dec - 2022	620,107	620,107	3.017	18,709,333
84					
85	<u>2022</u>				
86	Central Alabama	4,372,775	4,372,775	3.058	133,732,287
87	King Fisher	1,031,280	1,031,280	4.543	46,850,888
88	St Lucie Reliability	633,858	633,858	0.462	2,926,719
89	SWA	892,980	892,980	3.403	30,388,548
90	Subtotal 2022	6,930,893	6,930,893	3.086	213,898,442
91					
92	Note: Totals may not add due to rounding.				

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ENERGY PAYMENTS TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Estimated Payments	Total KWH Purchased (000)	KWH for Firm (000)	Fuel Cost (cents/KWH)	Total \$ for Fuel Adj
1	<u>Jan - 2022</u>				
2	Qualifying Facilities	49,890	49,890	3.638	1,815,148
3	Subtotal Jan - 2022	49,890	49,890	3.638	1,815,148
4					
5	<u>Feb - 2022</u>				
6	Qualifying Facilities	49,598	49,598	3.838	1,903,389
7	Subtotal Feb - 2022	49,598	49,598	3.838	1,903,389
8					
9	<u>Mar - 2022</u>				
10	Qualifying Facilities	57,971	57,971	3.910	2,266,916
11	Subtotal Mar - 2022	57,971	57,971	3.910	2,266,916
12					
13	<u>Apr - 2022</u>				
14	Qualifying Facilities	57,126	57,126	3.767	2,152,064
15	Subtotal Apr - 2022	57,126	57,126	3.767	2,152,064
16					
17	<u>May - 2022</u>				
18	Qualifying Facilities	66,209	66,209	3.518	2,329,066
19	Subtotal May - 2022	66,209	66,209	3.518	2,329,066
20					
21	<u>Jun - 2022</u>				
22	Qualifying Facilities	66,844	66,844	3.431	2,293,358
23	Subtotal Jun - 2022	66,844	66,844	3.431	2,293,358
24					
25	<u>Jul - 2022</u>				
26	Qualifying Facilities	65,100	65,100	3.502	2,280,045
27	Subtotal Jul - 2022	65,100	65,100	3.502	2,280,045
28					
29	<u>Aug - 2022</u>				
30	Qualifying Facilities	60,947	60,947	3.625	2,209,111
31	Subtotal Aug - 2022	60,947	60,947	3.625	2,209,111
32					
33	<u>Sep - 2022</u>				
34	Qualifying Facilities	57,136	57,136	3.555	2,031,423
35	Subtotal Sep - 2022	57,136	57,136	3.555	2,031,423
36					
37	<u>Oct - 2022</u>				

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ENERGY PAYMENTS TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Estimated Payments	Total KWH Purchased (000)	KWH for Firm (000)	Fuel Cost (cents/KWH)	Total \$ for Fuel Adj
38	Qualifying Facilities	56,811	56,811	3.651	2,074,109
39	Subtotal Oct - 2022	56,811	56,811	3.651	2,074,109
40					
41	<u>Nov - 2022</u>				
42	Qualifying Facilities	50,278	50,278	3.589	1,804,540
43	Subtotal Nov - 2022	50,278	50,278	3.589	1,804,540
44					
45	<u>Dec - 2022</u>				
46	Qualifying Facilities	47,726	47,726	3.425	1,634,738
47	Subtotal Dec - 2022	47,726	47,726	3.425	1,634,738
48					
49	<u>2022</u>				
50	Qualifying Facilities	685,635	685,635	3.616	24,793,908
51	Subtotal 2022	685,635	685,635	3.616	24,793,908
52					
53	Note: Totals may not add due to rounding.				

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Estimated Purchases	Type	Total KWH Purchase (000)	Transaction Cost (cents/kWh)	Total \$ for Fuel Adj	Cost if Generated (cents/kWh)	Cost if Generated (\$)	Fuel Savings (\$)
1	<u>Jan - 2022</u>							
2	Associated Interchange	IIC	25,096	2.913	731,092	2.913	731,092	
3	Economy	OS	4,914	3.306	162,441	3.306	162,441	
4	Subtotal Jan - 2022		30,010	2.977	893,533	2.977	893,533	
5								
6	<u>Feb - 2022</u>							
7	Associated Interchange	IIC	7,907	2.908	229,916	2.908	229,916	
8	Economy	OS	5,361	3.213	172,258	3.303	177,099	4,841
9	Subtotal Feb - 2022		13,269	3.031	402,174	3.068	407,015	4,841
10								
11	<u>Mar - 2022</u>							
12	Associated Interchange	IIC	16,973	2.711	460,171	2.711	460,171	
13	Economy	OS	18,753	3.001	562,707	3.223	604,328	41,621
14	Subtotal Mar - 2022		35,726	2.863	1,022,878	2.980	1,064,499	41,621
15								
16	<u>Apr - 2022</u>							
17	Associated Interchange	IIC	951	2.595	24,674	2.595	24,674	
18	Economy	OS	19,558	2.779	543,603	3.030	592,698	49,095
19	Subtotal Apr - 2022		20,509	2.771	568,276	3.010	617,371	49,095
20								
21	<u>May - 2022</u>							
22	Associated Interchange	IIC	11,300	2.355	266,135	2.355	266,135	
23	Economy	OS	134,657	2.468	3,322,749	2.754	3,708,832	386,083
24	Subtotal May - 2022		145,957	2.459	3,588,884	2.723	3,974,967	386,083
25								
26	<u>Jun - 2022</u>							
27	Associated Interchange	IIC	9,561	3.148	300,986	3.148	300,986	
28	Economy	OS	130,073	2.721	3,538,998	3.319	4,317,615	778,617
29	Subtotal Jun - 2022		139,635	2.750	3,839,984	3.308	4,618,601	778,617
30								
31	<u>Jul - 2022</u>							
32	Economy	OS	44,020	2.700	1,188,540	2.945	1,296,591	108,051
33	Subtotal Jul - 2022		44,020	2.700	1,188,540	2.945	1,296,591	108,051
34								
35	<u>Aug - 2022</u>							
36	Economy	OS	16,430	2.700	443,610	3.048	500,746	57,136
37	Subtotal Aug - 2022		16,430	2.700	443,610	3.048	500,746	57,136
38								
39	<u>Sep - 2022</u>							
40	Economy	OS	50,400	2.500	1,260,000	3.021	1,522,797	262,797
41	Subtotal Sep - 2022		50,400	2.500	1,260,000	3.021	1,522,797	262,797
42								

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
RESIDENTIAL BILL COMPARISON

SCHEDULE: E10

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

FPL	CURRENT	UNIFIED	DIFFERENCE	
	2021	JAN - DEC 2022	\$	%
BASE	\$69.90	\$75.82	\$5.92	8.47%
FUEL COST RECOVERY	\$25.10	\$28.22	\$3.12	12.43%
ENERGY CONSERVATION COST RECOVERY	\$1.49	\$1.34	-\$0.15	-10.07%
CAPACITY COST RECOVERY	\$2.04	\$2.39	\$0.35	17.16%
ENVIRONMENTAL COST RECOVERY	\$1.49	\$2.99	\$1.50	100.67%
STORM PROTECTION PLAN COST RECOVERY	\$0.42	\$2.14	\$1.72	409.52%
TRANSITION RIDER	<u>\$0.00</u>	<u>(\$1.98)</u>	<u>-\$1.98</u>	<u>N/A</u>
SUBTOTAL	\$100.44	\$110.92	\$10.48	10.43%
GROSS RECEIPTS TAX/REGULATORY ASSESSMENT FEE	<u>\$2.58</u>	<u>\$2.93</u>	<u>\$0.35</u>	<u>13.57%</u>
TOTAL	\$103.02	\$113.85	\$10.83	10.51%

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
RESIDENTIAL BILL COMPARISON

SCHEDULE: E10

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

GULF	CURRENT	UNIFIED	DIFFERENCE	
	2021	JAN - DEC 2022	\$	%
BASE	\$68.06	\$75.82	\$7.76	11.40%
FUEL COST RECOVERY	\$30.70	\$28.22	-\$2.48	-8.08%
ENERGY CONSERVATION COST RECOVERY	\$0.90	\$1.34	\$0.44	48.89%
CAPACITY COST RECOVERY	\$9.15	\$2.39	-\$6.76	-73.88%
ENVIRONMENTAL COST RECOVERY	\$16.21	\$2.99	-\$13.22	-81.55%
STORM PROTECTION PLAN COST RECOVERY	\$0.37	\$2.14	\$1.77	478.38%
STORM RESTORATION SURCHARGE	\$11.00	\$11.00	\$0.00	0.00%
TRANSITION RIDER	<u>\$0.00</u>	<u>\$21.06</u>	<u>\$21.06</u>	<u>NA</u>
SUBTOTAL	\$136.39	\$144.96	\$8.57	6.28%
GROSS RECEIPTS TAX/REGULATORY ASSESSMENT FEE	<u>\$3.50</u>	<u>\$3.82</u>	<u>\$0.32</u>	<u>9.14%</u>
TOTAL	\$139.89	\$148.78	\$8.89	6.35%

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE: H1

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

FCR - H1	2019	2020	2021	2022	% Diff Filing 2020 to 2019	% Diff Filing 2021 to 2020	% Diff Filing 2022 to 2021
<u>Fuel Cost of System Net Generation (\$)</u>							
Heavy Oil	13,793,931	6,864,055	12,136,129		(50.2%)	76.8%	(100.0%)
Light Oil	21,683,514	9,375,421	10,947,550	1,837,822	(56.8%)	16.8%	(83.2%)
Coal	215,209,523	133,045,384	137,529,885	47,715,079	(38.2%)	3.4%	(65.3%)
Gas	2,703,244,536	2,430,185,751	3,284,646,266	3,245,892,546	(10.1%)	35.2%	(1.2%)
Nuclear	159,950,571	148,402,742	150,340,308	147,539,060	(7.2%)	1.3%	(1.9%)
Subtotal Fuel Cost of System Net Generation (\$)	3,113,882,075	2,727,873,353	3,595,600,138	3,442,984,508	(12.4%)	31.8%	(4.2%)
<u>System Net Generation (MWh)</u>							
Heavy Oil	105,846	53,062	89,519		(49.9%)	68.7%	(100.0%)
Light Oil	223,784	65,629	80,554	16,316	(70.7%)	22.7%	(79.7%)
Coal	6,620,460	3,702,345	4,607,113	1,743,311	(44.1%)	24.4%	(62.2%)
Gas	97,475,625	100,719,913	95,422,307	94,662,974	3.3%	(5.3%)	(0.8%)
Nuclear	27,791,207	28,220,906	28,452,559	28,940,921	1.5%	0.8%	1.7%
Solar	2,369,165	3,912,922	6,095,653	8,121,040	65.2%	55.8%	33.2%
Subtotal System Net Generation (MWh)	134,586,088	136,674,777	134,747,705	133,484,562	1.6%	(1.4%)	(0.9%)
<u>Units of Fuel Burned (Unit)</u>							
Heavy Oil	188,991	94,056	163,921		(50.2%)	74.3%	(100.0%)
Light Oil	221,876	97,681	198,701	21,445	(56.0%)	103.4%	(89.2%)
Coal	3,604,901	2,200,633	2,595,792	1,018,086	(39.0%)	18.0%	(60.8%)
Gas	679,298,025	695,859,263	671,601,353	644,685,258	2.4%	(3.5%)	(4.0%)
Nuclear	303,397,508	306,991,995	303,946,697	305,036,436	1.2%	(1.0%)	0.4%
<u>BTU Burned (MMBTU)</u>							
Heavy Oil	1,196,123	595,280	1,043,314		(50.2%)	75.3%	(100.0%)
Light Oil	1,285,074	569,799	722,570	125,024	(55.7%)	26.8%	(82.7%)
Coal	73,157,867	42,888,272	49,674,916	18,051,053	(41.4%)	15.8%	(63.7%)
Gas	694,600,505	713,527,171	672,910,580	644,685,258	2.7%	(5.7%)	(4.2%)
Nuclear	303,397,508	306,991,995	303,946,697	305,036,436	1.2%	(1.0%)	0.4%
Subtotal BTU Burned (MMBTU)	1,073,637,078	1,064,572,517	1,028,298,077	967,897,771	(0.8%)	(3.4%)	(5.9%)
<u>Generation Mix (%)</u>							
Heavy Oil	0.08%	0.04%	0.07%				
Light Oil	0.17%	0.05%	0.06%	0.01%			
Coal	4.92%	2.71%	3.42%	1.31%			
Gas	72.43%	73.69%	70.82%	70.92%			
Nuclear	20.65%	20.65%	21.12%	21.68%			
Solar	1.76%	2.86%	4.52%	6.08%			
Subtotal Generation Mix (%)	100.00%	100.00%	100.00%	100.00%			
<u>Fuel Cost per Unit (\$/Unit)</u>							
Heavy Oil	72.9873	72.9784	74.0363		(0.0%)	1.4%	(100.0%)
Light Oil	97.7281	95.9800	55.0955	85.6995	(1.8%)	(42.6%)	55.5%
Coal	59.6991	60.4578	52.9819	46.8675	1.3%	(12.4%)	(11.5%)
Gas	3.9795	3.4924	4.8908	5.0348	(12.2%)	40.0%	2.9%
Nuclear	0.5272	0.4834	0.4946	0.4837	(8.3%)	2.3%	(2.2%)
<u>Fuel Cost per MMBTU (\$/MMBTU)</u>							
Heavy Oil	11.5322	11.5308	11.6323		(0.0%)	0.9%	(100.0%)
Light Oil	16.8734	16.4539	15.1508	14.6998	(2.5%)	(7.9%)	(3.0%)
Coal	2.9417	3.1021	2.7686	2.6433	5.5%	(10.8%)	(4.5%)
Gas	3.8918	3.4059	4.8813	5.0348	(12.5%)	43.3%	3.1%
Nuclear	0.5272	0.4834	0.4946	0.4837	(8.3%)	2.3%	(2.2%)
Subtotal Fuel Cost per MMBTU (\$/MMBTU)	2.9003	2.5624	3.4967	3.5572	(11.7%)	36.5%	1.7%
<u>BTU Burned per KWH (BTU/KWH)</u>							
Heavy Oil	11,301	11,219	11,655		(0.7%)	3.9%	(100.0%)
Light Oil	5,742	8,682	8,970	7,663	51.2%	3.3%	(14.6%)
Coal	11,050	11,584	10,782	10,354	4.8%	(6.9%)	(4.0%)
Gas	7,126	7,084	7,052	6,810	(0.6%)	(0.5%)	(3.4%)
Nuclear	10,917	10,878	10,683	10,540	(0.4%)	(1.8%)	(1.3%)
Subtotal BTU Burned per KWH (BTU/KWH)	7,977	7,789	7,631	7,251	(2.4%)	(2.0%)	(5.0%)
<u>Generated Fuel Cost per KWH (cents/KWH)</u>							
Heavy Oil	13.0320	12.9360	13.5570		(0.7%)	4.8%	(100.0%)
Light Oil	9.6895	14.2856	13.5904	11.2642	47.4%	(4.9%)	(17.1%)
Coal	3.2507	3.5935	2.9852	2.7370	10.5%	(16.9%)	(8.3%)
Gas	2.7733	2.4128	3.4422	3.4289	(13.0%)	42.7%	(0.4%)
Nuclear	0.5755	0.5259	0.5284	0.5098	(8.6%)	0.5%	(3.5%)
Subtotal Generated Fuel Cost per KWH (cents/KWH)	2.3137	1.9959	2.6684	2.5793	(13.7%)	33.7%	(3.3%)

FLORIDA POWER & LIGHT COMPANY

Forty-Eighth-Ninth Revised Sheet No. 10.101
Cancels ~~Forty-Eighth~~ ~~Forty-Seventh~~ Revised Sheet No. 10.101

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

FPL will provide its most recent non-binding estimate of future AS-Available avoided cost projections within thirty days of a written request. In addition, As-Available Energy cost payments will include ~~-0.1390~~0.01367¢/kWh for variable operation and maintenance expenses.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

<u>Delivery Voltage</u>	<u>Adjustment Factor</u>
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0144 <u>1.0109</u>
Secondary Voltage Delivery	1.0295 <u>1.0321</u>

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

FPL's projected annual generation mix may be found on Schedules 5, 6.1 and 6.2 in FPL's Ten Year Site Plan.

(Continued on Sheet No. 10.102)

FLORIDA POWER & LIGHT COMPANY

Forty-Ninth Revised Sheet No. 10.101
Cancels Forty-Eighth Revised Sheet No. 10.101

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

FPL will provide its most recent non-binding estimate of future AS-Available avoided cost projections within thirty days of a written request. In addition, As-Available Energy cost payments will include 0.01367¢/kWh for variable operation and maintenance expenses.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

<u>Delivery Voltage</u>	<u>Adjustment Factor</u>
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0109
Secondary Voltage Delivery	1.0321

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

FPL's projected annual generation mix may be found on Schedules 5, 6.1 and 6.2 in FPL's Ten Year Site Plan.

(Continued on Sheet No. 10.102)

FLORIDA POWER & LIGHT COMPANY

Forty-~~First~~^{Second} Revised Sheet No. 10.103
Cancels ~~Forty-First~~^{Fortieth} Revised Sheet No. 10.103

(Continued from Sheet No. 10.102)

B. Interconnection Charge for Non-Variable Utility Expenses:

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. Interconnection Charge for Variable Utility Expenses:

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

<u>Equipment Type</u>	<u>Charge</u>
Metering Equipment	0.075 ^{0.013} %
Distribution Equipment	0.227 ^{0.180} %
Transmission Equipment	0.130 ^{0.067} %

D. Taxes and Assessments

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

- (1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

FLORIDA POWER & LIGHT COMPANY

Forty-Second Revised Sheet No. 10.103
Cancels Forty-First Revised Sheet No. 10.103

(Continued from Sheet No. 10.102)

B. Interconnection Charge for Non-Variable Utility Expenses:

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. Interconnection Charge for Variable Utility Expenses:

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

<u>Equipment Type</u>	<u>Charge</u>
Metering Equipment	0.013%
Distribution Equipment	0.180%
Transmission Equipment	0.067%

D. Taxes and Assessments

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

- (1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX III-A

REVISED 2021 FPL FCR ACTUAL/ESTIMATED TRUE-UP

RBD-6
DOCKET NO. 20210001-EI
FPL WITNESS: RENAE B. DEATON
EXHIBIT _____
PAGES 1-44
SEPTEMBER 3, 2021

APPENDIX III-A

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FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.		a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	a-Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
1	Fuel Costs & Net Power Transactions													
2	Fuel Cost of System Net Generation (E3)	196,093,006	236,914,902	232,667,765	225,565,917	278,330,509	282,924,116	341,225,976	355,355,984	336,247,216	311,235,546	260,778,435	264,039,686	3,321,379,059
3	Rail Car Lease (Cedar Bay/Indiantown)	135,560	145,146	146,169	131,899	89,641	275,055	145,696	165,557	165,557	164,666	165,557	164,666	1,895,168
4	Fuel Cost of Stratified Sales	(2,029,516)	(2,426,951)	(3,092,458)	(2,549,736)	(2,702,691)	(3,957,871)	(1,875,769)	(2,110,086)	(2,097,265)	(1,672,301)	(1,374,606)	(951,556)	(26,840,805)
5	Fuel Cost of Power Sold (Per E6)	(3,036,111)	(4,808,540)	(3,570,186)	(5,100,462)	(4,246,828)	(6,427,033)	(9,699,740)	(4,076,180)	(3,982,556)	(3,590,407)	(4,882,444)	(4,845,887)	(58,266,375)
6	Gains from Off-System Sales (Per E6)	(1,039,604)	(4,412,077)	(1,385,402)	(1,948,740)	(1,689,592)	(2,498,511)	(4,716,567)	(1,410,502)	(1,366,865)	(1,368,411)	(1,705,853)	(1,636,460)	(25,178,585)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	2,653,162	3,079,694	3,466,300	2,196,670	2,839,335	2,849,346	2,938,627	2,758,335	2,353,189	2,459,689	2,631,543	2,859,802	33,085,692
8	Energy Payments to Qualifying Facilities (Per E8)	148,230	860,916	247,650	433,716	377,695	460,548	389,823	474,917	628,902	531,444	573,623	613,145	5,740,609
9	Energy Cost of Economy Purchases (Per E9)	0	335,359	229,632	608,471	9,533,861	5,356,987	152,030	492,900	1,436,400	1,193,500	0	0	19,339,141
10		192,924,727	229,688,448	228,709,470	219,337,736	282,531,932	278,982,637	328,560,074	351,650,925	333,384,578	308,953,727	256,186,254	260,243,396	3,271,153,904
11	Incremental Optimization Costs ⁽¹⁾													
12	Incremental Personnel, Software, and Hardware Costs	38,881	37,697	43,269	41,219	39,477	43,655	41,798	39,781	34,861	39,781	38,141	36,501	475,062
13	Var. Power Plant O&M Costs Attributable to Off-Sys Sales (E6)	111,151	162,731	114,110	156,034	110,209	167,747	246,933	95,713	89,115	89,466	141,765	133,595	1,618,570
14	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	0	(3,312)	(3,963)	(8,317)	(129,850)	(79,020)	(1,778)	(10,680)	(32,760)	(28,210)	(0)	(0)	(297,889)
15		150,032	197,117	153,416	188,936	19,836	132,382	286,953	124,814	91,216	101,037	179,906	170,096	1,795,743
16	Adjustments to Fuel Cost													
17	Energy Imbalance Fuel Revenue	(134,118)	(107,079)	(84,053)	(5,237)	(46,309)	(76,006)	(161,721)	0	0	0	0	0	(614,523)
18	Other O&M Expense	171	0	0	(4,624)	31,173	468,074	3,838	0	0	0	0	0	498,632
19	Inventory Adjustments	(12,731)	35,434	(93,166)	57,883	35,889	16,109	(939)	0	0	0	0	0	38,479
20		(146,678)	(71,646)	(177,219)	48,022	20,752	408,177	(158,822)	0	0	0	0	0	(77,412)
21	Adjusted Total Fuel Costs & Net Power Transactions	192,928,081	229,813,920	228,685,667	219,574,694	282,572,520	279,523,197	328,688,206	351,775,740	333,475,794	309,054,764	256,366,160	260,413,492	3,272,872,235
22	kWh Sales													
23	Retail kWh Sales	7,920,264,452	7,672,369,137	8,050,207,476	8,597,508,595	9,741,408,902	10,281,014,783	10,730,178,438	11,150,324,537	10,846,656,951	9,823,896,585	8,733,550,051	8,111,829,907	111,659,209,814
24	Sale for Resale	396,711,147	402,529,066	400,986,769	442,738,116	460,603,206	532,167,836	533,084,353	549,520,507	551,702,817	494,851,181	492,994,344	409,204,283	5,667,093,625
25		8,316,975,599	8,074,898,203	8,451,194,245	9,040,246,711	10,202,012,108	10,813,182,619	11,263,262,791	11,699,845,044	11,398,359,768	10,318,747,766	9,226,544,395	8,521,034,190	117,326,303,439
26														
27	Retail % of Total kWh Sales	95.23010%	95.01506%	95.25527%	95.10259%	95.48517%	95.07853%	95.26705%	95.30318%	95.15981%	95.20435%	94.65678%	95.19772%	
28														
29	Revenues Applicable to Period													
30	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	189,607,980	182,758,194	192,250,967	206,929,145	275,856,968	292,572,663	306,632,603	315,215,562	306,630,992	277,717,933	246,894,239	229,318,440	3,022,385,686
31	Prior Period True-Up (Collected)/Refunded This Period ⁽²⁾	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(1,722,493)	(20,669,910)
32	Midcourse Correction - Prior Year Final True-Up (Collected)/Refunded This Period	0	0	0	0	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(9,111,475)	(72,891,803)
33	GPIF, Net of Revenue Taxes ⁽³⁾	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(676,653)	(8,119,831)
34	Asset Optimization, Net of Revenue Taxes ⁽⁴⁾	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(724,772)	(8,697,268)
35	SolarTogether Credit, Net of Revenue Taxes ⁽⁵⁾	(2,233,951)	(3,807,644)	(3,861,993)	(5,607,909)	(7,442,029)	(9,161,666)	(7,789,381)	(9,126,203)	(8,843,399)	(7,947,258)	(7,852,929)	(6,614,903)	(80,289,267)
36		184,250,112	175,826,632	185,265,056	198,197,318	256,179,546	271,175,604	286,607,829	293,853,966	285,552,200	257,535,282	226,805,917	210,468,144	2,831,717,607
37	True-Up Calculation													
38	Adjusted Total Fuel Costs & Net Power Transactions	192,928,081	229,813,920	228,685,667	219,574,694	282,572,520	279,523,197	328,688,206	351,775,740	333,475,794	309,054,764	256,366,160	260,413,492	3,272,872,235
39	Jurisdictional Sales % of Total kWh Sales	95.23010%	95.01506%	95.25527%	95.10259%	95.48517%	95.07853%	95.26705%	95.30318%	95.15981%	95.20435%	94.65678%	95.19772%	
40	Retail Total Fuel Costs & Net Power Transactions	183,975,472	218,715,067	218,191,528	209,162,852	270,256,268	266,201,340	313,643,841	335,801,941	317,854,092	294,714,946	243,064,957	248,313,284	3,119,895,588
41	True-Up Provision for the Month-Over/(Under) Recovery	274,640	(42,888,435)	(32,926,472)	(10,965,534)	(14,076,722)	4,974,264	(27,036,011)	(41,947,975)	(32,301,892)	(37,179,663)	(16,259,040)	(37,845,140)	(288,177,981)
42	Interest Provision for the Month	(6,557)	(7,944)	(12,362)	(12,644)	(8,013)	(8,428)	(9,845)	(9,850)	(11,165)	(12,361)	(13,155)	(13,967)	(126,291)
43	True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	(20,669,910)	(18,679,334)	(59,853,221)	(91,069,563)	(100,325,247)	(112,687,490)	(105,999,162)	(131,322,526)	(171,557,858)	(202,148,422)	(237,617,954)	(252,167,657)	(20,669,910)
44	Deferred True-up Beginning of Period - Over/(Under) Recovery ⁽²⁾	(72,891,803)	(72,891,803)	(72,891,803)	(72,891,803)	(72,891,803)	(63,780,327)	(54,668,852)	(45,557,377)	(36,445,901)	(27,334,426)	(18,222,951)	(9,111,475)	(72,891,803)
45	Midcourse Correction - Prior Year Final True-Up (Collected)/Refunded This Period					9,111,475	9,111,475	9,111,475	9,111,475	9,111,475	9,111,475	9,111,475	9,111,475	72,891,803
46	Prior Period True Up Collected/(Refunded) This Period	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	1,722,493	20,669,910
47	End of Period Net True-up Amount Over/(Under) Recovery	(91,571,137)	(132,745,023)	(163,961,365)	(173,217,050)	(176,467,817)	(160,668,014)	(176,879,902)	(208,003,759)	(229,482,848)	(255,840,904)	(261,279,132)	(288,304,271)	(288,304,271)

⁽¹⁾ Amounts reflected in this section are in accordance with FPL's Stipulation and Settlement approved by the Commission in Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI

⁽²⁾ Estimated 2020 Final True-Up under-recovery

⁽³⁾ Generating Performance Incentive Factor is $((\$8,125,681/12) \times 99.9280\%)$ - See Order No. PSC-2020-0439-FOF-EI

⁽⁴⁾ Jurisdictionalized Asset Optimization - FPL Portion is $((\$8,703,535/12) \times 99.9280\%)$ - See Order No. PSC-2020-0439-FOF-EI

⁽⁵⁾ Approved in Order No. PSC-2020-0084-S-EI issued in Docket No. 20190061-EI on March 20, 2020

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.		a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	a-Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Fuel Cost of System Net Generation (\$)													
2	Heavy Oil	0	395,439	967,310	2,140,452	1,449,516	436,191	569,805	1,887,650	2,672,186	1,617,580	0	0	12,136,129
3	Light Oil	779,832	3,582,725	490,603	333,790	1,242,013	1,260,320	104,997	437,205	1,410,237	711,559	0	0	10,353,282
4	Coal	1,830,141	6,128,978	5,388,631	2,328,385	10,707,125	6,379,437	8,212,537	7,999,883	7,322,424	6,537,270	6,325,437	6,740,833	75,901,082
5	Gas	179,842,136	214,300,687	212,154,964	210,537,024	252,830,400	261,102,535	318,114,670	331,980,872	314,560,912	291,424,881	242,035,401	243,763,779	3,072,648,261
6	Nuclear	13,640,896	12,507,074	13,666,257	10,226,267	12,101,456	13,745,634	14,223,966	13,050,373	10,281,457	10,944,257	12,417,597	13,535,074	150,340,308
7	Subtotal Fuel Cost of System Net Generation (\$)	196,093,006	236,914,903	232,667,766	225,565,918	278,330,509	282,924,117	341,225,975	355,355,984	336,247,216	311,235,546	260,778,435	264,039,686	3,321,379,062
8														
9	System Net Generation (MWh)													
10	Heavy Oil	(1,846)	2,971	7,493	16,491	10,934	3,139	4,034	14,159	20,081	12,062	0	0	89,519
11	Light Oil	5,374	35,269	3,724	2,287	8,988	10,492	834	2,257	7,391	3,877	0	0	80,495
12	Coal	152,748	204,183	167,673	179,481	179,098	192,054	272,542	271,594	255,932	227,912	221,439	235,935	2,560,591
13	Gas	5,570,003	5,787,680	6,441,824	7,170,392	8,253,106	8,285,020	9,220,466	9,015,419	8,770,439	7,864,722	6,139,584	5,857,648	88,376,303
14	Nuclear	2,600,121	2,370,891	2,560,807	2,075,177	2,233,285	2,570,483	2,640,930	2,461,676	1,868,711	2,070,152	2,397,888	2,602,438	28,452,559
15	Solar	341,110	350,305	459,498	530,409	628,873	483,554	533,126	590,755	541,991	548,914	479,376	431,901	5,919,812
16	Subtotal System Net Generation (MWh)	8,667,511	8,751,299	9,641,019	9,974,237	11,314,284	11,544,743	12,671,933	12,355,860	11,464,546	10,727,640	9,238,287	9,127,922	125,479,279
17														
18	Units of Fuel Burned (Unit)													
19	Heavy Oil		5,418	13,253	29,327	19,859	5,976	7,609	25,204	35,679	21,598			163,921
20	Light Oil	7,907	40,985	5,052	3,615	13,485	12,516	1,223	5,725	18,191	7,486			116,185
21	Coal	49,863	134,559	116,324	47,707	122,185	132,975	184,652	174,502	164,817	149,096	144,393	153,430	1,574,503
22	Gas	39,204,052	40,987,540	46,132,513	50,753,622	58,604,478	58,426,451	64,655,730	62,021,350	59,966,913	53,584,351	41,255,868	39,677,942	615,270,810
23	Nuclear	27,649,786	25,358,591	27,420,987	22,533,770	24,363,299	27,788,854	28,707,754	26,221,278	19,985,311	21,966,592	24,903,353	27,047,123	303,946,697
24														
25														
26	BTU Burned (MMBTU)													
27	Heavy Oil	0	34,290	83,879	185,608	125,688	37,822	48,156	161,303	228,343	138,225	0	0	1,043,314
28	Light Oil	45,626	239,929	29,259	20,966	77,934	73,400	7,060	33,375	106,055	43,646	0	0	677,250
29	Coal	653,395	2,253,298	1,948,721	797,380	3,893,973	2,255,665	2,875,842	2,966,527	2,801,894	2,534,628	2,454,674	2,608,309	28,044,306
30	Gas	39,204,052	40,987,540	46,132,513	50,753,622	58,604,478	58,426,451	64,655,730	62,021,350	59,966,913	53,584,351	41,255,868	39,677,942	615,270,810
31	Nuclear	27,649,786	25,358,591	27,420,987	22,533,770	24,363,299	27,788,854	28,707,754	26,221,278	19,985,311	21,966,592	24,903,353	27,047,123	303,946,697
32	Subtotal BTU Burned (MMBTU)	67,552,859	68,873,648	75,615,360	74,291,346	87,065,372	88,582,192	96,294,542	91,403,833	83,088,516	78,267,442	68,613,895	69,333,374	948,982,377
33														
34	Fuel Cost per Unit (\$/Unit)													
35	Heavy Oil		72.9870	72.9871	72.9869	72.9904	72.9905	74.8876	74.8961	74.8961	74.8961			74.0363
36	Light Oil	98.6255	87.4155	97.1106	92.3346	92.1033	100.6967	85.8522	76.3716	77.5228	95.0463			89.1100
37	Coal	36.7032	45.5485	46.3242	48.8063	87.6305	47.9747	44.4756	45.8442	44.4275	43.8461	43.8072	43.9343	48.2064
38	Gas	4.5873	5.2284	4.5988	4.1482	4.3142	4.4689	4.9201	5.3527	5.2456	5.4386	5.8667	6.1436	4.9940
39	Nuclear	0.4933	0.4932	0.4984	0.4538	0.4967	0.4946	0.4955	0.4977	0.5145	0.4982	0.4986	0.5004	0.4946
40														
41	Generation Mix (%)													
42	Heavy Oil	(0.02%)	0.03%	0.08%	0.17%	0.10%	0.03%	0.03%	0.11%	0.18%	0.11%	0%	0%	0.07%
43	Light Oil	0.06%	0.40%	0.04%	0.02%	0.08%	0.09%	0.01%	0.02%	0.06%	0.04%	0%	0%	0.06%
44	Coal	1.76%	2.33%	1.74%	1.80%	1.58%	1.66%	2.15%	2.20%	2.23%	2.12%	2.40%	2.58%	2.04%
45	Gas	64.26%	66.14%	66.82%	71.89%	72.94%	71.76%	72.76%	72.96%	76.50%	73.31%	66.46%	64.17%	70.43%
46	Nuclear	30.00%	27.09%	26.56%	20.81%	19.74%	22.27%	20.84%	19.92%	16.30%	19.30%	25.96%	28.51%	22.68%
47	Solar	3.94%	4.00%	4.77%	5.32%	5.56%	4.19%	4.21%	4.78%	4.73%	5.12%	5.19%	4.73%	4.72%
48														

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.		a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	a-Jun - 2021	a-Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	<u>Fuel Cost per MMBTU (\$/MMBTU)</u>													
2	Heavy Oil		11.5322	11.5322	11.5321	11.5327	11.5327	11.8325	11.7025	11.7025	11.7025			11.6323
3	Light Oil	17.0920	14.9324	16.7674	15.9201	15.9367	17.1707	14.8725	13.0998	13.2972	16.3030			15.2872
4	Coal	2.8010	2.7200	2.7652	2.9200	2.7497	2.8282	2.8557	2.6967	2.6134	2.5792	2.5769	2.5844	2.7065
5	Gas	4.5873	5.2284	4.5988	4.1482	4.3142	4.4689	4.9201	5.3527	5.2456	5.4386	5.8667	6.1436	4.9940
6	Nuclear	0.4933	0.4932	0.4984	0.4538	0.4967	0.4946	0.4955	0.4977	0.5145	0.4982	0.4986	0.5004	0.4946
7														
8	<u>BTU Burned per KWH (BTU/KWH)</u>													
9	Heavy Oil	0	11,540	11,194	11,255	11,496	12,048	11,936	11,392	11,371	11,459	0	0	11,655
10	Light Oil	8,490	6,803	7,856	9,167	8,671	6,995	8,462	14,787	14,349	11,257	0	0	8,414
11	Coal	4,278	11,036	11,622	4,443	21,742	11,745	10,552	10,923	10,948	11,121	11,085	11,055	10,952
12	Gas	7,038	7,082	7,161	7,078	7,101	7,052	7,012	6,879	6,837	6,813	6,720	6,774	6,962
13	Nuclear	10,634	10,696	10,708	10,859	10,909	10,811	10,870	10,652	10,695	10,611	10,386	10,393	10,683
14														
15	<u>Generated Fuel Cost per KWH (cents/KWH)</u>													
16	Heavy Oil		13.3086	12.9095	12.9794	13.2575	13.8947	14.1238	13.3319	13.3072	13.4101			13.5570
17	Light Oil	14.5104	10.1583	13.1728	14.5941	13.8182	12.0117	12.5857	19.3711	19.0805	18.3531			12.8621
18	Coal	1.1981	3.0017	3.2138	1.2973	5.9784	3.3217	3.0133	2.9455	2.8611	2.8683	2.8565	2.8571	2.9642
19	Gas	3.2288	3.7027	3.2934	2.9362	3.0635	3.1515	3.4501	3.6824	3.5866	3.7055	3.9422	4.1615	3.4768
20	Nuclear	0.5246	0.5275	0.5337	0.4928	0.5419	0.5347	0.5386	0.5301	0.5502	0.5287	0.5179	0.5201	0.5284
21	Subtotal Generated Fuel Cost per KWH (cents/KWH)	2.2624	2.7072	2.4133	2.2615	2.4600	2.4507	2.6928	2.8760	2.9329	2.9012	2.8228	2.8927	2.6470
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FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Aug - 2021												
2	Babcock Preserve ST Solar												
3	Solar		14,937					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75.0	14,937	27.0%	N/A	27.0%	N/A						
5	Babcock PV Solar												
6	Solar		14,342					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	75.0	14,342	26.0%	N/A	26.0%	N/A						
8	Barefoot PV Solar												
9	Solar		15,018					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	75.0	15,018	27.0%	N/A	27.0%	N/A						
11	Blue Cypress PV Solar												
12	Solar		15,243					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	75.0	15,243	28.0%	N/A	28.0%	N/A						
14	Blue Heron ST Solar												
15	Solar		14,937					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	75.0	14,937	27.0%	N/A	27.0%	N/A						
17	Cape Canaveral 3												
18	Light Oil		0				0	0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
21	Cattle Ranch ST Solar												
22	Solar		15,651					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	75.0	15,651	28.0%	N/A	28.0%	N/A						
24	CCEC 3												
25	Gas		476,905				6,719	3,204,297	1,000,000	3,204,297	17,432,024	3.66	5.44
26	Plant Unit Info	1,308.0	476,905	49.0%	93.0%	52.0%	6,719			3,204,297	17,432,024	3.66	
27	Citrus PV Solar												
28	Solar		14,611					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	14,611	26.0%	N/A	26.0%	N/A						
30	Coral Farms PV Solar												
31	Solar		16,129					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	16,129	29.0%	N/A	29.0%	N/A						
33	Dania Beach												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Desoto Solar												
3	Solar		4,326					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	25.0	4,326	23.0%	N/A	23.0%	N/A						
5	Discovery PV Solar												
6	Solar		12,412					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	75.0	12,412	22.0%	N/A	22.0%	N/A						
8	Echo River PV Solar												
9	Solar		18,710					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	75.0	18,710	34.0%	N/A	34.0%	N/A						
11	Egret PV Solar												
12	Solar		13,338					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	75.0	13,338	24.0%	N/A	24.0%	N/A						
14	Elder Branch PV Solar												
15	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
17	Fort Drum PV Solar												
18	Solar		12,697					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	75.0	12,697	23.0%	N/A	23.0%	N/A						
20	Fort Myers 2												
21	Gas		812,683				7,005	5,693,077	1,000,000	5,693,077	30,962,353	3.81	5.44
22	Plant Unit Info	1,700.0	812,683	64.0%	94.0%	69.0%	7,005			5,693,077	30,962,353	3.81	
23	Fort Myers 3A												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	162.0	0	N/A	94.0%	N/A	N/A						
27	Fort Myers 3B												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	166.0	0	N/A	94.0%	N/A	N/A						
31	Fort Myers 3C												
32	Light Oil		0				0	0	0	0	0	0.00	0.00
33	Gas		16,851				10,523	177,328	1,000,000	177,328	966,665	5.74	5.45
34	Plant Unit Info	219.0	16,851	10.0%	94.0%	11.0%	10,523			177,328	966,665	5.74	
35	Fort Myers 3D												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		16,088				10,524	169,317	1,000,000	169,317	922,318	5.73	5.45
3	Plant Unit Info	219.0	16,088	10.0%	94.0%	11.0%	10,524			169,317	922,318	5.73	
4	Fort Myers GT												
5	Light Oil		0				0	0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Ghost Orchid PV Solar												
8	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
10	Grove PV Solar												
11	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
13	Hammock PV Solar												
14	Solar		15,279					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	75.0	15,279	28.0%	N/A	28.0%	N/A						
16	Hibiscus PV Solar												
17	Solar		15,424					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	15,424	28.0%	N/A	28.0%	N/A						
19	Horizon PV Solar												
20	Solar		16,140					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	16,140	29.0%	N/A	29.0%	N/A						
22	Immokalee PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Indian River PV Solar												
26	Solar		15,230					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	15,230	27.0%	N/A	27.0%	N/A						
28	Indiantown FPL												
29	Coal											N/A	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
32	Interstate PV Solar												
33	Solar		15,104					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	75.0	15,104	27.0%	N/A	27.0%	N/A						
35	Lakeside PV Solar												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		13,728					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	75.0	13,728	25.0%	N/A	25.0%	N/A						
3	Lauderdale 1-12												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Lauderdale 6A												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		13,931				10,580	147,386	1,000,000	147,386	802,307	5.76	5.44
10	Plant Unit Info	216.0	13,931	9.0%	94.0%	9.0%	10,580			147,386	802,307	5.76	
11	Lauderdale 6B												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		11,925				10,607	126,493	1,000,000	126,493	689,259	5.78	5.45
14	Plant Unit Info	216.0	11,925	7.0%	94.0%	8.0%	10,607			126,493	689,259	5.78	
15	Lauderdale 6C												
16	Light Oil		1,146				14,659	2,881	5,829,990	16,799	220,063	19.20	76.37
17	Gas		0					0	0	0	0	0.00	0.00
18	Plant Unit Info	216.0	1,146	1.0%	94.0%	1.0%	14,659			16,799	220,063	19.20	
19	Lauderdale 6D												
20	Light Oil		644				13,738	1,518	5,829,984	8,847	115,894	18.00	76.37
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	216.0	644	N/A	94.0%	N/A	13,738			8,847	115,894	18.00	
23	Lauderdale 6E												
24	Light Oil		467				16,550	1,326	5,829,996	7,729	101,248	21.68	76.37
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	216.0	467	N/A	94.0%	N/A	16,550			7,729	101,248	21.68	
27	Loggerhead PV Solar												
28	Solar		15,258					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	15,258	28.0%	N/A	28.0%	N/A						
30	Magnolia PV Solar												
31	Solar		14,179					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	14,179	26.0%	N/A	26.0%	N/A						
33	Manatee 1												
34	Heavy Oil		7,876				10,586	13,027	6,399,999	83,371	975,650	12.39	74.90
35	Gas		160,052				10,586	1,694,241	1,000,000	1,694,241	8,711,156	5.44	5.14

FLORIDA POWER & LIGHT COMPANY
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ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	789.0	167,928	29.0%	94.0%	30.0%	10,586			1,777,612	9,686,806	5.77	
2	Manatee 2												
3	Heavy Oil		6,283				12,404	12,177	6,399,997	77,932	912,000	14.52	74.90
4	Gas		81,338				12,404	1,008,895	1,000,000	1,008,895	5,186,595	6.38	5.14
5	Plant Unit Info	789.0	87,621	15.0%	94.0%	16.0%	12,404			1,086,827	6,098,595	6.96	
6	Manatee 3												
7	Gas		630,075				6,839	4,309,207	1,000,000	4,309,207	22,138,580	3.51	5.14
8	Plant Unit Info	1,223.0	630,075	69.0%	94.0%	74.0%	6,839			4,309,207	22,138,580	3.51	
9	Manatee PV Solar												
10	Solar		14,390					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	14,390	26.0%	N/A	26.0%	N/A						
12	Martin 3												
13	Gas		178,461				7,371	1,315,486	1,000,000	1,315,486	7,027,677	3.94	5.34
14	Plant Unit Info	464.0	178,461	52.0%	94.0%	55.0%	7,371			1,315,486	7,027,677	3.94	
15	Martin 4												
16	Gas		177,259				7,366	1,305,706	1,000,000	1,305,706	6,970,944	3.93	5.34
17	Plant Unit Info	464.0	177,259	51.0%	94.0%	55.0%	7,366			1,305,706	6,970,944	3.93	
18	Martin 8												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		502,992				6,971	3,506,463	1,000,000	3,506,463	19,045,899	3.79	5.43
21	Plant Unit Info	1,218.0	502,992	56.0%	94.0%	59.0%	6,971			3,506,463	19,045,899	3.79	
22	Martin 8 Solar												
23	Solar		11,873					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	55.0	11,873	29.0%	N/A	29.0%	N/A						
25	Miami-Dade PV Solar												
26	Solar		14,745					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	14,745	27.0%	N/A	27.0%	N/A						
28	Nassau PV Solar												
29	Solar		12,931					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	12,931	23.0%	N/A	23.0%	N/A						
31	Northern Preserve ST Solar												
32	Solar		12,982					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	12,982	23.0%	N/A	23.0%	N/A						
34	OKEECHOBEE 1												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		1,038,922				6,284	6,528,487	1,000,000	6,528,487	36,013,745	3.47	5.52
2	Plant Unit Info	1,603.0	1,038,922	87.0%	93.0%	94.0%	6,284			6,528,487	36,013,745	3.47	
3	Okeechobee PV Solar												
4	Solar		15,842					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	75.0	15,842	29.0%	N/A	29.0%	N/A						
6	Orange Blossom PV Solar												
7	Solar		13,405					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	75.0	13,405	24.0%	N/A	24.0%	N/A						
9	Palm Bay PV Solar												
10	Solar		13,282					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	13,282	24.0%	N/A	24.0%	N/A						
12	PEEC												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		834,740				6,351	5,301,829	1,000,000	5,301,829	28,833,256	3.45	5.44
15	Plant Unit Info	1,254.0	834,740	89.0%	93.0%	96.0%	6,351			5,301,829	28,833,256	3.45	
16	Pelican PV Solar												
17	Solar		13,405					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	13,405	24.0%	N/A	24.0%	N/A						
19	Pioneer Trail PV Solar												
20	Solar		15,069					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	15,069	27.0%	N/A	27.0%	N/A						
22	Riviera 5												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		617,062				6,660	4,109,937	1,000,000	4,109,937	22,669,989	3.67	5.52
25	Plant Unit Info	1,308.0	617,062	63.0%	93.0%	68.0%	6,660			4,109,937	22,669,989	3.67	
26	Rodeo PV Solar												
27	Solar		14,363					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	75.0	14,363	26.0%	N/A	26.0%	N/A						
29	Sabal Palm PV Solar												
30	Solar		13,623					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	75.0	13,623	25.0%	N/A	25.0%	N/A						
32	Sanford 4												
33	Gas		493,027				6,934	3,418,596	1,000,000	3,418,596	18,605,056	3.77	5.44
34	Plant Unit Info	1,147.0	493,027	58.0%	94.0%	61.0%	6,934			3,418,596	18,605,056	3.77	
35	Sanford 5												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		498,327				6,931	3,453,854	1,000,000	3,453,854	18,797,767	3.77	5.44
2	Plant Unit Info	1,147.0	498,327	58.0%	94.0%	62.0%	6,931			3,453,854	18,797,767	3.77	
3	Sawgrass PV Solar												
4	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
6	Scherer 4												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Coal		271,594				10,923	174,502	17,000,000	2,966,527	7,999,883	2.95	45.84
9	Plant Unit Info	636.0	271,594	57.0%	92.0%	62.0%	10,923			2,966,527	7,999,883	2.95	
10	Southfork PV Solar												
11	Solar		18,357					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	75.0	18,357	33.0%	N/A	33.0%	N/A						
13	Space Coast												
14	Solar		1,545					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	10.0	1,545	21.0%	100.0%	21.0%	N/A						
16	St Lucie 1												
17	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,602,343	0.51	0.48
18	Plant Unit Info	981.0	711,586	98.0%	98.0%	100.0%	10,560			7,514,275	3,602,343	0.51	
19	St Lucie 2												
20	Nuclear		530,674				10,496	5,569,790	1,000,000	5,569,790	2,426,200	0.46	0.44
21	Plant Unit Info	840.0	530,674	85.0%	85.0%	100.0%	10,496			5,569,790	2,426,200	0.46	
22	Sundew PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Sunshine Gateway PV Solar												
26	Solar		15,292					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	15,292	28.0%	N/A	28.0%	N/A						
28	Sweetbay PV Solar												
29	Solar		13,274					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	13,274	24.0%	N/A	24.0%	N/A						
31	Trailside PV Solar												
32	Solar		14,652					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	14,652	26.0%	N/A	26.0%	N/A						
34	Turkey Point 3												
35	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,131,956	0.52	0.48

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	837.0	607,178	98.0%	98.0%	100.0%	10,818			6,568,699	3,131,956	0.52	
2	Turkey Point 4												
3	Nuclear		612,238				10,729	6,568,514	1,000,000	6,568,514	3,889,874	0.64	0.59
4	Plant Unit Info	844.0	612,238	98.0%	98.0%	100.0%	10,729			6,568,514	3,889,874	0.64	
5	Turkey Point 5												
6	Light Oil		0				0	0	0	0	0	0.00	0.00
7	Gas		570,546				6,867	3,917,855	1,000,000	3,917,855	21,319,792	3.74	5.44
8	Plant Unit Info	1,256.0	570,546	61.0%	94.0%	65.0%	6,867			3,917,855	21,319,792	3.74	
9	Twin Lakes ST Solar												
10	Solar		15,230					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	15,230	27.0%	N/A	27.0%	N/A						
12	Union Springs PV Solar												
13	Solar		14,342					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	75.0	14,342	26.0%	N/A	26.0%	N/A						
15	WCEC 01												
16	Light Oil		0				0	0	0	0	0	0.00	0.00
17	Gas		573,070				6,749	3,867,854	1,000,000	3,867,854	19,865,836	3.47	5.14
18	Plant Unit Info	1,223.0	573,070	63.0%	94.0%	67.0%	6,749			3,867,854	19,865,836	3.47	
19	WCEC 02												
20	Light Oil		0				0	0	0	0	0	0.00	0.00
21	Gas		584,282				6,746	3,941,349	1,000,000	3,941,349	20,242,888	3.46	5.14
22	Plant Unit Info	1,223.0	584,282	64.0%	94.0%	69.0%	6,746			3,941,349	20,242,888	3.46	
23	WCEC 03												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		726,883				6,636	4,823,693	1,000,000	4,823,693	24,776,767	3.41	5.14
26	Plant Unit Info	1,228.0	726,883	80.0%	94.0%	85.0%	6,636			4,823,693	24,776,767	3.41	
27	Wildflower PV Solar												
28	Solar		15,359					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	15,359	28.0%	N/A	28.0%	N/A						
30	Willow PV Solar												
31	Solar		14,101					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	14,101	25.0%	N/A	25.0%	N/A						
33	System Totals												
34	Plant Unit Info	28,343	12,355,860				7,398			91,403,833	355,355,984	2.88	N/A
35	Total												

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Sep - 2021												
2	Babcock Preserve ST Solar												
3	Solar		14,167					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75.0	14,167	26.0%	N/A	26.0%	N/A						
5	Babcock PV Solar												
6	Solar		12,899					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	75.0	12,899	24.0%	N/A	24.0%	N/A						
8	Barefoot PV Solar												
9	Solar		13,957					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	75.0	13,957	26.0%	N/A	26.0%	N/A						
11	Blue Cypress PV Solar												
12	Solar		14,290					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	75.0	14,290	27.0%	N/A	27.0%	N/A						
14	Blue Heron ST Solar												
15	Solar		14,167					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	75.0	14,167	26.0%	N/A	26.0%	N/A						
17	Cape Canaveral 3												
18	Light Oil		0				0	0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
21	Cattle Ranch ST Solar												
22	Solar		14,415					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	75.0	14,415	27.0%	N/A	27.0%	N/A						
24	CCEC 3												
25	Gas		413,654				6,741	2,788,242	1,000,000	2,788,242	14,867,462	3.59	5.33
26	Plant Unit Info	1,308.0	413,654	44.0%	76.0%	58.0%	6,741			2,788,242	14,867,462	3.59	
27	Citrus PV Solar												
28	Solar		13,630					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	13,630	25.0%	N/A	25.0%	N/A						
30	Coral Farms PV Solar												
31	Solar		14,602					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	14,602	27.0%	N/A	27.0%	N/A						
33	Dania Beach												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		0					0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Desoto Solar												
3	Solar		3,868					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	25.0	3,868	21.0%	N/A	21.0%	N/A						
5	Discovery PV Solar												
6	Solar		11,389					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	75.0	11,389	21.0%	N/A	21.0%	N/A						
8	Echo River PV Solar												
9	Solar		16,335					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	75.0	16,335	30.0%	N/A	30.0%	N/A						
11	Egret PV Solar												
12	Solar		11,797					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	75.0	11,797	22.0%	N/A	22.0%	N/A						
14	Elder Branch PV Solar												
15	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
17	Fort Drum PV Solar												
18	Solar		11,487					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	75.0	11,487	21.0%	N/A	21.0%	N/A						
20	Fort Myers 2												
21	Gas		801,063				7,011	5,616,306	1,000,000	5,616,306	29,967,918	3.74	5.34
22	Plant Unit Info	1,700.0	801,063	65.0%	94.0%	70.0%	7,011			5,616,306	29,967,918	3.74	
23	Fort Myers 3A												
24	Light Oil		478				13,676	1,121	5,829,996	6,537	106,573	22.30	95.05
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	162.0	478	N/A	94.0%	N/A	13,676			6,537	106,573	22.30	
27	Fort Myers 3B												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	166.0	0	N/A	94.0%	N/A	N/A						
31	Fort Myers 3C												
32	Light Oil		0				0	0	0	0	0	0.00	0.00
33	Gas		21,467				10,511	225,645	1,000,000	225,645	1,202,087	5.60	5.33
34	Plant Unit Info	219.0	21,467	14.0%	94.0%	15.0%	10,511			225,645	1,202,087	5.60	
35	Fort Myers 3D												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		17,124				10,501	179,823	1,000,000	179,823	958,192	5.60	5.33
3	Plant Unit Info	219.0	17,124	11.0%	94.0%	12.0%	10,501			179,823	958,192	5.60	
4	Fort Myers GT												
5	Light Oil		0				0	0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Ghost Orchid PV Solar												
8	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
10	Grove PV Solar												
11	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
13	Hammock PV Solar												
14	Solar		14,411					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	75.0	14,411	27.0%	N/A	27.0%	N/A						
16	Hibiscus PV Solar												
17	Solar		13,975					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	13,975	26.0%	N/A	26.0%	N/A						
19	Horizon PV Solar												
20	Solar		14,806					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	14,806	28.0%	N/A	28.0%	N/A						
22	Immokalee PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Indian River PV Solar												
26	Solar		14,277					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	14,277	27.0%	N/A	27.0%	N/A						
28	Indiantown FPL												
29	Coal											N/A	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
32	Interstate PV Solar												
33	Solar		14,079					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	75.0	14,079	26.0%	N/A	26.0%	N/A						
35	Lakeside PV Solar												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		12,736					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	75.0	12,736	24.0%	N/A	24.0%	N/A						
3	Lauderdale 1-12												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Lauderdale 6A												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		14,644				10,532	154,228	1,000,000	154,228	821,829	5.61	5.33
10	Plant Unit Info	216.0	14,644	9.0%	94.0%	10.0%	10,532			154,228	821,829	5.61	
11	Lauderdale 6B												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		15,045				10,525	158,347	1,000,000	158,347	843,431	5.61	5.33
14	Plant Unit Info	216.0	15,045	10.0%	94.0%	10.0%	10,525			158,347	843,431	5.61	
15	Lauderdale 6C												
16	Light Oil		2,882				13,985	6,913	5,829,999	40,305	527,987	18.32	76.37
17	Gas		0					0	0	0	0	0.00	0.00
18	Plant Unit Info	216.0	2,882	2.0%	94.0%	2.0%	13,985			40,305	527,987	18.32	
19	Lauderdale 6D												
20	Light Oil		1,935				14,344	4,761	5,830,002	27,756	363,598	18.79	76.37
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	216.0	1,935	1.0%	94.0%	1.0%	14,344			27,756	363,598	18.79	
23	Lauderdale 6E												
24	Light Oil		2,096				15,008	5,396	5,830,002	31,457	412,080	19.66	76.37
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	216.0	2,096	1.0%	94.0%	1.0%	15,008			31,457	412,080	19.66	
27	Loggerhead PV Solar												
28	Solar		14,449					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	14,449	27.0%	N/A	27.0%	N/A						
30	Magnolia PV Solar												
31	Solar		12,435					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	12,435	23.0%	N/A	23.0%	N/A						
33	Manatee 1												
34	Heavy Oil		11,426				10,800	19,280	6,400,000	123,395	1,444,031	12.64	74.90
35	Gas		65,149				10,800	703,599	1,000,000	703,599	3,549,726	5.45	5.05

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	789.0	76,574	13.0%	94.0%	14.0%	10,800			826,994	4,993,757	6.52	
2	Manatee 2												
3	Heavy Oil		8,655				12,125	16,398	6,399,998	104,948	1,228,155	14.19	74.90
4	Gas		81,168				12,125	984,191	1,000,000	984,191	4,960,177	6.11	5.04
5	Plant Unit Info	789.0	89,823	16.0%	94.0%	17.0%	12,125			1,089,139	6,188,332	6.89	
6	Manatee 3												
7	Gas		635,290				6,826	4,336,571	1,000,000	4,336,571	21,856,482	3.44	5.04
8	Plant Unit Info	1,223.0	635,290	72.0%	94.0%	77.0%	6,826			4,336,571	21,856,482	3.44	
9	Manatee PV Solar												
10	Solar		13,678					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	13,678	26.0%	N/A	26.0%	N/A						
12	Martin 3												
13	Gas		175,386				7,370	1,292,549	1,000,000	1,292,549	6,713,328	3.83	5.19
14	Plant Unit Info	464.0	175,386	53.0%	94.0%	56.0%	7,370			1,292,549	6,713,328	3.83	
15	Martin 4												
16	Gas		78,409				7,361	577,153	1,000,000	577,153	3,017,995	3.85	5.23
17	Plant Unit Info	464.0	78,409	23.0%	41.0%	58.0%	7,361			577,153	3,017,995	3.85	
18	Martin 8												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		608,607				6,918	4,210,257	1,000,000	4,210,257	22,188,011	3.65	5.27
21	Plant Unit Info	1,218.0	608,607	69.0%	94.0%	74.0%	6,918			4,210,257	22,188,011	3.65	
22	Martin 8 Solar												
23	Solar		10,320					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	55.0	10,320	26.0%	N/A	26.0%	N/A						
25	Miami-Dade PV Solar												
26	Solar		13,518					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	13,518	25.0%	N/A	25.0%	N/A						
28	Nassau PV Solar												
29	Solar		11,335					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	11,335	21.0%	N/A	21.0%	N/A						
31	Northern Preserve ST Solar												
32	Solar		12,314					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	12,314	23.0%	N/A	23.0%	N/A						
34	OKEECHOBEE 1												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		1,028,135				6,277	6,454,111	1,000,000	6,454,111	34,780,712	3.38	5.39
2	Plant Unit Info	1,603.0	1,028,135	89.0%	93.0%	96.0%	6,277			6,454,111	34,780,712	3.38	
3	Okeechobee PV Solar												
4	Solar		14,608					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	75.0	14,608	27.0%	N/A	27.0%	N/A						
6	Orange Blossom PV Solar												
7	Solar		12,397					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	75.0	12,397	23.0%	N/A	23.0%	N/A						
9	Palm Bay PV Solar												
10	Solar		12,260					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	12,260	23.0%	N/A	23.0%	N/A						
12	PEEC												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		803,429				6,355	5,105,413	1,000,000	5,105,413	27,247,866	3.39	5.34
15	Plant Unit Info	1,254.0	803,429	89.0%	93.0%	96.0%	6,355			5,105,413	27,247,866	3.39	
16	Pelican PV Solar												
17	Solar		12,397					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	12,397	23.0%	N/A	23.0%	N/A						
19	Pioneer Trail PV Solar												
20	Solar		13,694					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	13,694	26.0%	N/A	26.0%	N/A						
22	Riviera 5												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		607,697				6,657	4,045,556	1,000,000	4,045,556	21,801,194	3.59	5.39
25	Plant Unit Info	1,308.0	607,697	65.0%	93.0%	69.0%	6,657			4,045,556	21,801,194	3.59	
26	Rodeo PV Solar												
27	Solar		13,109					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	75.0	13,109	24.0%	N/A	24.0%	N/A						
29	Sabal Palm PV Solar												
30	Solar		12,575					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	75.0	12,575	23.0%	N/A	23.0%	N/A						
32	Sanford 4												
33	Gas		489,476				6,946	3,400,106	1,000,000	3,400,106	18,153,120	3.71	5.34
34	Plant Unit Info	1,147.0	489,476	59.0%	94.0%	63.0%	6,946			3,400,106	18,153,120	3.71	
35	Sanford 5												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		490,973				6,949	3,411,668	1,000,000	3,411,668	18,212,338	3.71	5.34
2	Plant Unit Info	1,147.0	490,973	59.0%	94.0%	63.0%	6,949			3,411,668	18,212,338	3.71	
3	Sawgrass PV Solar												
4	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
6	Scherer 4												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Coal		255,932				10,948	164,817	17,000,000	2,801,894	7,322,424	2.86	44.43
9	Plant Unit Info	636.0	255,932	56.0%	92.0%	61.0%	10,948			2,801,894	7,322,424	2.86	
10	Southfork PV Solar												
11	Solar		16,374					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	75.0	16,374	31.0%	N/A	31.0%	N/A						
13	Space Coast												
14	Solar		1,421					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	10.0	1,421	20.0%	100.0%	20.0%	N/A						
16	St Lucie 1												
17	Nuclear		688,631				10,560	7,271,879	1,000,000	7,271,879	3,486,138	0.51	0.48
18	Plant Unit Info	981.0	688,631	98.0%	98.0%	100.0%	10,560			7,271,879	3,486,138	0.51	
19	St Lucie 2												
20	Nuclear											N/A	0.00
21	Plant Unit Info	840.0	0	N/A	N/A	N/A	N/A						
22	Sundew PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Sunshine Gateway PV Solar												
26	Solar		14,199					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	14,199	26.0%	N/A	26.0%	N/A						
28	Sweetbay PV Solar												
29	Solar		12,663					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	12,663	24.0%	N/A	24.0%	N/A						
31	Trailside PV Solar												
32	Solar		12,560					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	12,560	23.0%	N/A	23.0%	N/A						
34	Turkey Point 3												
35	Nuclear		587,592				10,818	6,356,806	1,000,000	6,356,806	3,030,925	0.52	0.48

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	837.0	587,592	98.0%	98.0%	100.0%	10,818			6,356,806	3,030,925	0.52	
2	Turkey Point 4												
3	Nuclear		592,488				10,729	6,356,626	1,000,000	6,356,626	3,764,394	0.64	0.59
4	Plant Unit Info	844.0	592,488	98.0%	98.0%	100.0%	10,729			6,356,626	3,764,394	0.64	
5	Turkey Point 5												
6	Light Oil		0				0	0	0	0	0	0.00	0.00
7	Gas		568,922				6,869	3,907,840	1,000,000	3,907,840	20,862,492	3.67	5.34
8	Plant Unit Info	1,256.0	568,922	63.0%	94.0%	67.0%	6,869			3,907,840	20,862,492	3.67	
9	Twin Lakes ST Solar												
10	Solar		14,028					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	14,028	26.0%	N/A	26.0%	N/A						
12	Union Springs PV Solar												
13	Solar		12,577					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	75.0	12,577	23.0%	N/A	23.0%	N/A						
15	WCEC 01												
16	Light Oil		0				0	0	0	0	0	0.00	0.00
17	Gas		556,091				6,746	3,751,654	1,000,000	3,751,654	18,903,394	3.40	5.04
18	Plant Unit Info	1,223.0	556,091	63.0%	91.0%	69.0%	6,746			3,751,654	18,903,394	3.40	
19	WCEC 02												
20	Light Oil		0				0	0	0	0	0	0.00	0.00
21	Gas		558,510				6,749	3,769,344	1,000,000	3,769,344	18,992,421	3.40	5.04
22	Plant Unit Info	1,223.0	558,510	63.0%	94.0%	68.0%	6,749			3,769,344	18,992,421	3.40	
23	WCEC 03												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		740,201				6,612	4,894,310	1,000,000	4,894,310	24,660,739	3.33	5.04
26	Plant Unit Info	1,228.0	740,201	84.0%	94.0%	89.0%	6,612			4,894,310	24,660,739	3.33	
27	Wildflower PV Solar												
28	Solar		14,791					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	14,791	28.0%	N/A	28.0%	N/A						
30	Willow PV Solar												
31	Solar		13,002					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	13,002	24.0%	N/A	24.0%	N/A						
33	System Totals												
34	Plant Unit Info	28,343	11,464,546				7,247			83,088,516	336,247,216	2.93	N/A
35	Total												

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FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Oct - 2021												
2	Babcock Preserve ST Solar												
3	Solar		14,948					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75.0	14,948	27.0%	N/A	27.0%	N/A						
5	Babcock PV Solar												
6	Solar		13,941					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	75.0	13,941	25.0%	N/A	25.0%	N/A						
8	Barefoot PV Solar												
9	Solar		14,309					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	75.0	14,309	26.0%	N/A	26.0%	N/A						
11	Blue Cypress PV Solar												
12	Solar		14,540					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	75.0	14,540	26.0%	N/A	26.0%	N/A						
14	Blue Heron ST Solar												
15	Solar		14,948					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	75.0	14,948	27.0%	N/A	27.0%	N/A						
17	Cape Canaveral 3												
18	Light Oil		0				0	0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
21	Cattle Ranch ST Solar												
22	Solar		14,269					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	75.0	14,269	26.0%	N/A	26.0%	N/A						
24	CCEC 3												
25	Gas		450,782				6,744	3,040,106	1,000,000	3,040,106	16,839,313	3.74	5.54
26	Plant Unit Info	1,308.0	450,782	46.0%	91.0%	51.0%	6,744			3,040,106	16,839,313	3.74	
27	Citrus PV Solar												
28	Solar		14,046					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	14,046	25.0%	N/A	25.0%	N/A						
30	Coral Farms PV Solar												
31	Solar		15,020					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	15,020	27.0%	N/A	27.0%	N/A						
33	Dania Beach												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		0					0	0	0	0	0.00	0.00

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Desoto Solar												
3	Solar		3,833					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	25.0	3,833	21.0%	N/A	21.0%	N/A						
5	Discovery PV Solar												
6	Solar		11,518					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	75.0	11,518	21.0%	N/A	21.0%	N/A						
8	Echo River PV Solar												
9	Solar		16,339					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	75.0	16,339	29.0%	N/A	29.0%	N/A						
11	Egret PV Solar												
12	Solar		11,683					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	75.0	11,683	21.0%	N/A	21.0%	N/A						
14	Elder Branch PV Solar												
15	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
17	Fort Drum PV Solar												
18	Solar		11,407					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	75.0	11,407	21.0%	N/A	21.0%	N/A						
20	Fort Myers 2												
21	Gas		775,376				7,038	5,456,720	1,000,000	5,456,720	30,199,214	3.89	5.53
22	Plant Unit Info	1,700.0	775,376	61.0%	84.0%	73.0%	7,038			5,456,720	30,199,214	3.89	
23	Fort Myers 3A												
24	Light Oil		1,201				11,584	2,386	5,830,008	13,909	226,758	18.88	95.05
25	Gas		2,676				11,584	31,002	1,000,000	31,002	173,664	6.49	5.60
26	Plant Unit Info	162.0	3,877	3.0%	94.0%	3.0%	11,584			44,911	400,422	10.33	
27	Fort Myers 3B												
28	Light Oil		1,242				11,663	2,484	5,829,992	14,481	236,083	19.01	95.05
29	Gas		2,326				11,663	27,134	1,000,000	27,134	152,136	6.54	5.61
30	Plant Unit Info	166.0	3,568	3.0%	94.0%	3.0%	11,663			41,615	388,220	10.88	
31	Fort Myers 3C												
32	Light Oil		418				10,667	766	5,830,024	4,463	72,760	17.39	95.05
33	Gas		22,525				10,666	240,268	1,000,000	240,268	1,337,418	5.94	5.57
34	Plant Unit Info	219.0	22,944	14.0%	94.0%	15.0%	10,666			244,731	1,410,178	6.15	
35	Fort Myers 3D												

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		1,016				10,620	1,851	5,829,989	10,793	175,958	17.31	95.05
2	Gas		19,869				10,620	211,003	1,000,000	211,003	1,173,984	5.91	5.56
3	Plant Unit Info	219.0	20,885	13.0%	94.0%	14.0%	10,620			221,796	1,349,942	6.46	
4	Fort Myers GT												
5	Light Oil		0				0	0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Ghost Orchid PV Solar												
8	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
10	Grove PV Solar												
11	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
13	Hammock PV Solar												
14	Solar		15,340					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	75.0	15,340	28.0%	N/A	28.0%	N/A						
16	Hibiscus PV Solar												
17	Solar		13,972					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	13,972	25.0%	N/A	25.0%	N/A						
19	Horizon PV Solar												
20	Solar		15,171					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	15,171	27.0%	N/A	27.0%	N/A						
22	Immokalee PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Indian River PV Solar												
26	Solar		14,532					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	14,532	26.0%	N/A	26.0%	N/A						
28	Indiantown FPL												
29	Coal											N/A	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
32	Interstate PV Solar												
33	Solar		14,238					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	75.0	14,238	26.0%	N/A	26.0%	N/A						
35	Lakeside PV Solar												

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		12,782					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	75.0	12,782	23.0%	N/A	23.0%	N/A						
3	Lauderdale 1-12												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Lauderdale 6A												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		14,443				10,515	151,869	1,000,000	151,869	844,879	5.85	5.56
10	Plant Unit Info	216.0	14,443	9.0%	94.0%	10.0%	10,515			151,869	844,879	5.85	
11	Lauderdale 6B												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		14,844				10,508	155,987	1,000,000	155,987	867,899	5.85	5.56
14	Plant Unit Info	216.0	14,844	9.0%	94.0%	10.0%	10,508			155,987	867,899	5.85	
15	Lauderdale 6C												
16	Light Oil		0				0	0	0	0	0	0.00	0.00
17	Gas		16,138				10,555	170,338	1,000,000	170,338	948,010	5.87	5.57
18	Plant Unit Info	216.0	16,138	10.0%	94.0%	11.0%	10,555			170,338	948,010	5.87	
19	Lauderdale 6D												
20	Light Oil		0				0	0	0	0	0	0.00	0.00
21	Gas		14,132				10,554	149,145	1,000,000	149,145	829,169	5.87	5.56
22	Plant Unit Info	216.0	14,132	9.0%	94.0%	9.0%	10,554			149,145	829,169	5.87	
23	Lauderdale 6E												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		16,940				10,542	178,575	1,000,000	178,575	993,853	5.87	5.57
26	Plant Unit Info	216.0	16,940	11.0%	94.0%	11.0%	10,542			178,575	993,853	5.87	
27	Loggerhead PV Solar												
28	Solar		14,876					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	14,876	27.0%	N/A	27.0%	N/A						
30	Magnolia PV Solar												
31	Solar		12,256					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	12,256	22.0%	N/A	22.0%	N/A						
33	Manatee 1												
34	Heavy Oil		5,630				11,333	9,970	6,399,998	63,806	746,690	13.26	74.90
35	Gas		33,618				11,333	380,976	1,000,000	380,976	2,001,366	5.95	5.25

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	789.0	39,248	7.0%	94.0%	7.0%	11,333			444,782	2,748,056	7.00	
2	Manatee 2												
3	Heavy Oil		6,432				11,570	11,628	6,399,999	74,419	870,889	13.54	74.90
4	Gas		17,085				11,570	197,670	1,000,000	197,670	1,038,409	6.08	5.25
5	Plant Unit Info	789.0	23,517	4.0%	94.0%	4.0%	11,570			272,089	1,909,299	8.12	
6	Manatee 3												
7	Gas		672,923				6,823	4,591,552	1,000,000	4,591,552	24,145,513	3.59	5.26
8	Plant Unit Info	1,223.0	672,923	74.0%	94.0%	79.0%	6,823			4,591,552	24,145,513	3.59	
9	Manatee PV Solar												
10	Solar		14,472					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	14,472	26.0%	N/A	26.0%	N/A						
12	Martin 3												
13	Gas		136,134				7,512	1,022,644	1,000,000	1,022,644	5,439,920	4.00	5.32
14	Plant Unit Info	464.0	136,134	39.0%	94.0%	42.0%	7,512			1,022,644	5,439,920	4.00	
15	Martin 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	464.0	0	N/A	N/A	N/A	N/A						
18	Martin 8												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		643,154				6,907	4,442,357	1,000,000	4,442,357	23,564,950	3.66	5.30
21	Plant Unit Info	1,218.0	643,154	71.0%	94.0%	76.0%	6,907			4,442,357	23,564,950	3.66	
22	Martin 8 Solar												
23	Solar		9,114					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	55.0	9,114	22.0%	N/A	22.0%	N/A						
25	Miami-Dade PV Solar												
26	Solar		13,970					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	13,970	25.0%	N/A	25.0%	N/A						
28	Nassau PV Solar												
29	Solar		11,267					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	11,267	20.0%	N/A	20.0%	N/A						
31	Northern Preserve ST Solar												
32	Solar		12,992					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	12,992	23.0%	N/A	23.0%	N/A						
34	OKEECHOBEE 1												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		964,622				6,308	6,085,307	1,000,000	6,085,307	34,035,097	3.53	5.59
2	Plant Unit Info	1,603.0	964,622	81.0%	93.0%	87.0%	6,308			6,085,307	34,035,097	3.53	
3	Okeechobee PV Solar												
4	Solar		14,662					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	75.0	14,662	26.0%	N/A	26.0%	N/A						
6	Orange Blossom PV Solar												
7	Solar		12,418					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	75.0	12,418	22.0%	N/A	22.0%	N/A						
9	Palm Bay PV Solar												
10	Solar		12,264					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	12,264	22.0%	N/A	22.0%	N/A						
12	PEEC												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		809,325				6,365	5,151,384	1,000,000	5,151,384	28,504,700	3.52	5.53
15	Plant Unit Info	1,254.0	809,325	87.0%	93.0%	93.0%	6,365			5,151,384	28,504,700	3.52	
16	Pelican PV Solar												
17	Solar		12,418					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	12,418	22.0%	N/A	22.0%	N/A						
19	Pioneer Trail PV Solar												
20	Solar		13,603					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	13,603	25.0%	N/A	25.0%	N/A						
22	Riviera 5												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		554,059				6,687	3,705,144	1,000,000	3,705,144	20,693,155	3.73	5.58
25	Plant Unit Info	1,308.0	554,059	57.0%	93.0%	61.0%	6,687			3,705,144	20,693,155	3.73	
26	Rodeo PV Solar												
27	Solar		12,810					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	75.0	12,810	23.0%	N/A	23.0%	N/A						
29	Sabal Palm PV Solar												
30	Solar		12,698					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	75.0	12,698	23.0%	N/A	23.0%	N/A						
32	Sanford 4												
33	Gas		56,934				7,136	406,272	1,000,000	406,272	2,257,482	3.97	5.56
34	Plant Unit Info	1,147.0	56,934	7.0%	17.0%	40.0%	7,136			406,272	2,257,482	3.97	
35	Sanford 5												

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		482,754				6,981	3,370,090	1,000,000	3,370,090	18,667,489	3.87	5.54
2	Plant Unit Info	1,147.0	482,754	57.0%	94.0%	60.0%	6,981			3,370,090	18,667,489	3.87	
3	Sawgrass PV Solar												
4	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
6	Scherer 4												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Coal		227,912				11,121	149,096	17,000,001	2,534,628	6,537,270	2.87	43.85
9	Plant Unit Info	636.0	227,912	48.0%	92.0%	52.0%	11,121			2,534,628	6,537,270	2.87	
10	Southfork PV Solar												
11	Solar		16,729					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	75.0	16,729	30.0%	N/A	30.0%	N/A						
13	Space Coast												
14	Solar		1,451					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	10.0	1,451	20.0%	100.0%	20.0%	N/A						
16	St Lucie 1												
17	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,602,343	0.51	0.48
18	Plant Unit Info	981.0	711,586	98.0%	98.0%	100.0%	10,560			7,514,275	3,602,343	0.51	
19	St Lucie 2												
20	Nuclear		589,637				10,496	6,188,655	1,000,000	6,188,655	2,643,793	0.45	0.43
21	Plant Unit Info	840.0	589,637	94.0%	94.0%	100.0%	10,496			6,188,655	2,643,793	0.45	
22	Sundew PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Sunshine Gateway PV Solar												
26	Solar		14,347					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	14,347	26.0%	N/A	26.0%	N/A						
28	Sweetbay PV Solar												
29	Solar		13,027					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	13,027	24.0%	N/A	24.0%	N/A						
31	Trailside PV Solar												
32	Solar		11,968					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	11,968	22.0%	N/A	22.0%	N/A						
34	Turkey Point 3												
35	Nuclear		156,691				10,818	1,695,148	1,000,000	1,695,148	808,247	0.52	0.48

FLORIDA POWER & LIGHT COMPANY
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	837.0	156,691	23.0%	23.0%	100.0%	10,818			1,695,148	808,247	0.52	
2	Turkey Point 4												
3	Nuclear		612,238				10,729	6,568,514	1,000,000	6,568,514	3,889,874	0.64	0.59
4	Plant Unit Info	844.0	612,238	98.0%	98.0%	100.0%	10,729			6,568,514	3,889,874	0.64	
5	Turkey Point 5												
6	Light Oil		0				0	0	0	0	0	0.00	0.00
7	Gas		433,307				6,973	3,021,562	1,000,000	3,021,562	16,774,637	3.87	5.55
8	Plant Unit Info	1,256.0	433,307	46.0%	94.0%	49.0%	6,973			3,021,562	16,774,637	3.87	
9	Twin Lakes ST Solar												
10	Solar		13,886					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	13,886	25.0%	N/A	25.0%	N/A						
12	Union Springs PV Solar												
13	Solar		12,397					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	75.0	12,397	22.0%	N/A	22.0%	N/A						
15	WCEC 01												
16	Light Oil		0				0	0	0	0	0	0.00	0.00
17	Gas		278,476				6,796	1,892,503	1,000,000	1,892,503	9,968,527	3.58	5.27
18	Plant Unit Info	1,223.0	278,476	31.0%	46.0%	66.0%	6,796			1,892,503	9,968,527	3.58	
19	WCEC 02												
20	Light Oil		0				0	0	0	0	0	0.00	0.00
21	Gas		701,564				6,664	4,675,284	1,000,000	4,675,284	24,586,223	3.50	5.26
22	Plant Unit Info	1,223.0	701,564	77.0%	94.0%	82.0%	6,664			4,675,284	24,586,223	3.50	
23	WCEC 03												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		730,716				6,609	4,829,459	1,000,000	4,829,459	25,387,874	3.47	5.26
26	Plant Unit Info	1,228.0	730,716	80.0%	87.0%	92.0%	6,609			4,829,459	25,387,874	3.47	
27	Wildflower PV Solar												
28	Solar		15,474					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	15,474	28.0%	N/A	28.0%	N/A						
30	Willow PV Solar												
31	Solar		12,979					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	12,979	23.0%	N/A	23.0%	N/A						
33	System Totals												
34	Plant Unit Info	28,343	10,727,640				7,296			78,267,442	311,235,546	2.90	N/A
35	Total												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Nov - 2021</u>												
2	Babcock Preserve ST Solar												
3	Solar		<u>13,755</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
4	Plant Unit Info	75.0	13,755	26.0%	N/A	26.0%	N/A						
5	Babcock PV Solar												
6	Solar		<u>12,647</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
7	Plant Unit Info	75.0	12,647	24.0%	N/A	24.0%	N/A						
8	Barefoot PV Solar												
9	Solar		<u>12,750</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
10	Plant Unit Info	75.0	12,750	24.0%	N/A	24.0%	N/A						
11	Blue Cypress PV Solar												
12	Solar		<u>13,101</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
13	Plant Unit Info	75.0	13,101	24.0%	N/A	24.0%	N/A						
14	Blue Heron ST Solar												
15	Solar		<u>13,755</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
16	Plant Unit Info	75.0	13,755	26.0%	N/A	26.0%	N/A						
17	Cape Canaveral 3												
18	Light Oil		0				0	0	0	0	0	0.00	0.00
19	Gas		<u>0</u>					0	0	<u>0</u>	<u>0</u>	<u>0.00</u>	0.00
20	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
21	Cattle Ranch ST Solar												
22	Solar		<u>12,159</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
23	Plant Unit Info	75.0	12,159	23.0%	N/A	23.0%	N/A						
24	CCEC 3												
25	Gas		<u>465,001</u>				6,676	3,104,205	1,000,000	<u>3,104,205</u>	<u>18,255,042</u>	<u>3.93</u>	5.88
26	Plant Unit Info	1,326.0	465,001	49.0%	93.0%	52.0%	6,676			<u>3,104,205</u>	<u>18,255,042</u>	<u>3.93</u>	
27	Citrus PV Solar												
28	Solar		<u>12,570</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
29	Plant Unit Info	75.0	12,570	23.0%	N/A	23.0%	N/A						
30	Coral Farms PV Solar												
31	Solar		<u>13,212</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
32	Plant Unit Info	75.0	13,212	25.0%	N/A	25.0%	N/A						
33	Dania Beach												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		0					0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Desoto Solar												
3	Solar		3,261					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	25.0	3,261	18.0%	N/A	18.0%	N/A						
5	Discovery PV Solar												
6	Solar		10,194					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	75.0	10,194	19.0%	N/A	19.0%	N/A						
8	Echo River PV Solar												
9	Solar		13,329					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	75.0	13,329	25.0%	N/A	25.0%	N/A						
11	Egret PV Solar												
12	Solar		9,806					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	75.0	9,806	18.0%	N/A	18.0%	N/A						
14	Elder Branch PV Solar												
15	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
17	Fort Drum PV Solar												
18	Solar		9,979					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	75.0	9,979	19.0%	N/A	19.0%	N/A						
20	Fort Myers 2												
21	Gas		365,766				7,019	2,567,443	1,000,000	2,567,443	15,088,931	4.13	5.88
22	Plant Unit Info	1,740.0	365,766	29.0%	42.0%	70.0%	7,019			2,567,443	15,088,931	4.13	
23	Fort Myers 3A												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		1,716				10,930	18,756	1,000,000	18,756	111,022	6.47	5.92
26	Plant Unit Info	189.0	1,716	1.0%	77.0%	2.0%	10,930			18,756	111,022	6.47	
27	Fort Myers 3B												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		2,544				11,005	27,996	1,000,000	27,996	165,334	6.50	5.91
30	Plant Unit Info	193.0	2,544	2.0%	77.0%	2.0%	11,005			27,996	165,334	6.50	
31	Fort Myers 3C												
32	Light Oil		0				0	0	0	0	0	0.00	0.00
33	Gas		3,974				10,686	42,468	1,000,000	42,468	251,893	6.34	5.93
34	Plant Unit Info	221.0	3,974	3.0%	77.0%	3.0%	10,686			42,468	251,893	6.34	
35	Fort Myers 3D												

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		4,791				10,615	50,858	1,000,000	50,858	301,093	6.28	5.92
3	Plant Unit Info	221.0	4,791	3.0%	77.0%	4.0%	10,615			50,858	301,093	6.28	
4	Fort Myers GT												
5	Light Oil		0				0	0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Ghost Orchid PV Solar												
8	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
10	Grove PV Solar												
11	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
13	Hammock PV Solar												
14	Solar		14,053					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	75.0	14,053	26.0%	N/A	26.0%	N/A						
16	Hibiscus PV Solar												
17	Solar		12,211					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	12,211	23.0%	N/A	23.0%	N/A						
19	Horizon PV Solar												
20	Solar		13,335					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	13,335	25.0%	N/A	25.0%	N/A						
22	Immokalee PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Indian River PV Solar												
26	Solar		13,089					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	13,089	24.0%	N/A	24.0%	N/A						
28	Indiantown FPL												
29	Coal											N/A	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
32	Interstate PV Solar												
33	Solar		12,422					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	75.0	12,422	23.0%	N/A	23.0%	N/A						
35	Lakeside PV Solar												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		11,171					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	75.0	11,171	21.0%	N/A	21.0%	N/A						
3	Lauderdale 1-12												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Lauderdale 6A												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		4,050				10,590	42,890	1,000,000	42,890	254,685	6.29	5.94
10	Plant Unit Info	218.0	4,050	3.0%	94.0%	3.0%	10,590			42,890	254,685	6.29	
11	Lauderdale 6B												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		4,050				10,590	42,890	1,000,000	42,890	254,030	6.27	5.92
14	Plant Unit Info	218.0	4,050	3.0%	94.0%	3.0%	10,590			42,890	254,030	6.27	
15	Lauderdale 6C												
16	Light Oil		0				0	0	0	0	0	0.00	0.00
17	Gas		4,050				10,590	42,890	1,000,000	42,890	253,979	6.27	5.92
18	Plant Unit Info	218.0	4,050	3.0%	94.0%	3.0%	10,590			42,890	253,979	6.27	
19	Lauderdale 6D												
20	Light Oil		0				0	0	0	0	0	0.00	0.00
21	Gas		4,050				10,590	42,890	1,000,000	42,890	253,979	6.27	5.92
22	Plant Unit Info	218.0	4,050	3.0%	94.0%	3.0%	10,590			42,890	253,979	6.27	
23	Lauderdale 6E												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		3,938				10,721	42,220	1,000,000	42,220	249,666	6.34	5.91
26	Plant Unit Info	218.0	3,938	3.0%	94.0%	3.0%	10,721			42,220	249,666	6.34	
27	Loggerhead PV Solar												
28	Solar		13,286					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	13,286	25.0%	N/A	25.0%	N/A						
30	Magnolia PV Solar												
31	Solar		9,787					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	9,787	18.0%	N/A	18.0%	N/A						
33	Manatee 1												
34	Heavy Oil											N/A	0.00
35	Gas		0					0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
2	Manatee 2												
3	Heavy Oil											N/A	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
6	Manatee 3												
7	Gas		607,681				6,841	4,157,188	1,000,000	4,157,188	24,153,889	3.97	5.81
8	Plant Unit Info	1,254.0	607,681	67.0%	94.0%	72.0%	6,841			4,157,188	24,153,889	3.97	
9	Manatee PV Solar												
10	Solar		12,714					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	12,714	24.0%	N/A	24.0%	N/A						
12	Martin 3												
13	Gas		28,138				7,735	217,649	1,000,000	217,649	1,275,725	4.53	5.86
14	Plant Unit Info	492.0	28,138	8.0%	94.0%	8.0%	7,735			217,649	1,275,725	4.53	
15	Martin 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	492.0	0	N/A	17.0%	N/A	N/A						
18	Martin 8												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		395,046				6,930	2,737,763	1,000,000	2,737,763	15,921,157	4.03	5.82
21	Plant Unit Info	1,258.0	395,046	44.0%	94.0%	47.0%	6,930			2,737,763	15,921,157	4.03	
22	Martin 8 Solar												
23	Solar		6,510					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	55.0	6,510	16.0%	N/A	16.0%	N/A						
25	Miami-Dade PV Solar												
26	Solar		13,058					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	13,058	24.0%	N/A	24.0%	N/A						
28	Nassau PV Solar												
29	Solar		9,442					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	9,442	18.0%	N/A	18.0%	N/A						
31	Northern Preserve ST Solar												
32	Solar		11,955					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	11,955	22.0%	N/A	22.0%	N/A						
34	OKEECHOBEE 1												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		683,005				6,370	4,350,659	1,000,000	4,350,659	26,001,231	3.81	5.98
2	Plant Unit Info	1,640.0	683,005	58.0%	70.0%	83.0%	6,370			4,350,659	26,001,231	3.81	
3	Okeechobee PV Solar												
4	Solar		12,724					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	75.0	12,724	24.0%	N/A	24.0%	N/A						
6	Orange Blossom PV Solar												
7	Solar		10,986					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	75.0	10,986	20.0%	N/A	20.0%	N/A						
9	Palm Bay PV Solar												
10	Solar		10,818					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	10,818	20.0%	N/A	20.0%	N/A						
12	PEEC												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		832,318				6,336	5,273,849	1,000,000	5,273,849	31,010,973	3.73	5.88
15	Plant Unit Info	1,283.0	832,318	90.0%	93.0%	97.0%	6,336			5,273,849	31,010,973	3.73	
16	Pelican PV Solar												
17	Solar		10,986					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	10,986	20.0%	N/A	20.0%	N/A						
19	Pioneer Trail PV Solar												
20	Solar		12,082					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	12,082	23.0%	N/A	23.0%	N/A						
22	Riviera 5												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		456,413				6,678	3,048,077	1,000,000	3,048,077	18,100,898	3.97	5.94
25	Plant Unit Info	1,326.0	456,413	48.0%	93.0%	51.0%	6,678			3,048,077	18,100,898	3.97	
26	Rodeo PV Solar												
27	Solar		10,751					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	75.0	10,751	20.0%	N/A	20.0%	N/A						
29	Sabal Palm PV Solar												
30	Solar		11,292					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	75.0	11,292	21.0%	N/A	21.0%	N/A						
32	Sanford 4												
33	Gas		102,870				7,015	721,680	1,000,000	721,680	4,256,382	4.14	5.90
34	Plant Unit Info	1,192.0	102,870	12.0%	94.0%	13.0%	7,015			721,680	4,256,382	4.14	
35	Sanford 5												

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		415,381				6,935	2,880,582	1,000,000	2,880,582	16,941,281	4.08	5.88
2	Plant Unit Info	1,192.0	415,381	48.0%	94.0%	51.0%	6,935			2,880,582	16,941,281	4.08	
3	Sawgrass PV Solar												
4	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
6	Scherer 4												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Coal		221,439				11,085	144,393	17,000,000	2,454,674	6,325,437	2.86	43.81
9	Plant Unit Info	626.0	221,439	49.0%	92.0%	53.0%	11,085			2,454,674	6,325,437	2.86	
10	Southfork PV Solar												
11	Solar		14,045					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	75.0	14,045	26.0%	N/A	26.0%	N/A						
13	Space Coast												
14	Solar		1,255					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	10.0	1,255	17.0%	100.0%	17.0%	N/A						
16	St Lucie 1												
17	Nuclear		704,121				10,328	7,272,374	1,000,000	7,272,374	3,486,376	0.50	0.48
18	Plant Unit Info	1,003.0	704,121	98.0%	98.0%	100.0%	10,328			7,272,374	3,486,376	0.50	
19	St Lucie 2												
20	Nuclear		603,399				10,257	6,188,882	1,000,000	6,188,882	2,643,891	0.44	0.43
21	Plant Unit Info	860.0	603,399	98.0%	98.0%	100.0%	10,257			6,188,882	2,643,891	0.44	
22	Sundew PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Sunshine Gateway PV Solar												
26	Solar		12,701					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	12,701	24.0%	N/A	24.0%	N/A						
28	Sweetbay PV Solar												
29	Solar		11,706					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	11,706	22.0%	N/A	22.0%	N/A						
31	Trailside PV Solar												
32	Solar		9,753					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	9,753	18.0%	N/A	18.0%	N/A						
34	Turkey Point 3												
35	Nuclear		482,400				10,541	5,085,123	1,000,000	5,085,123	2,522,730	0.52	0.50

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	859.0	482,400	78.0%	78.0%	100.0%	10,541			5,085,123	2,522,730	0.52	
2	Turkey Point 4												
3	Nuclear		607,968				10,456	6,356,974	1,000,000	6,356,974	3,764,600	0.62	0.59
4	Plant Unit Info	866.0	607,968	98.0%	98.0%	100.0%	10,456			6,356,974	3,764,600	0.62	
5	Turkey Point 5												
6	Light Oil		0				0	0	0	0	0	0.00	0.00
7	Gas		213,930				7,020	1,501,875	1,000,000	1,501,875	8,847,889	4.14	5.89
8	Plant Unit Info	1,294.0	213,930	23.0%	69.0%	33.0%	7,020			1,501,875	8,847,889	4.14	
9	Twin Lakes ST Solar												
10	Solar		11,832					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	11,832	22.0%	N/A	22.0%	N/A						
12	Union Springs PV Solar												
13	Solar		9,899					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	75.0	9,899	18.0%	N/A	18.0%	N/A						
15	WCEC 01												
16	Light Oil		0				0	0	0	0	0	0.00	0.00
17	Gas		512,096				6,742	3,452,620	1,000,000	3,452,620	20,061,463	3.92	5.81
18	Plant Unit Info	1,248.0	512,096	57.0%	94.0%	61.0%	6,742			3,452,620	20,061,463	3.92	
19	WCEC 02												
20	Light Oil		0				0	0	0	0	0	0.00	0.00
21	Gas		548,432				6,731	3,691,437	1,000,000	3,691,437	21,448,923	3.91	5.81
22	Plant Unit Info	1,248.0	548,432	61.0%	94.0%	65.0%	6,731			3,691,437	21,448,923	3.91	
23	WCEC 03												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		480,344				6,656	3,196,983	1,000,000	3,196,983	18,575,935	3.87	5.81
26	Plant Unit Info	1,254.0	480,344	53.0%	60.0%	88.0%	6,656			3,196,983	18,575,935	3.87	
27	Wildflower PV Solar												
28	Solar		13,864					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	13,864	26.0%	N/A	26.0%	N/A						
30	Willow PV Solar												
31	Solar		11,131					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	11,131	21.0%	N/A	21.0%	N/A						
33	System Totals												
34	Plant Unit Info	28,976	9,238,287				7,427			68,613,895	260,778,435	2.82	N/A
35	Total												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	<u>Dec - 2021</u>												
2	Babcock Preserve ST Solar												
3	Solar		<u>12,564</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
4	Plant Unit Info	75.0	12,564	23.0%	N/A	23.0%	N/A						
5	Babcock PV Solar												
6	Solar		<u>11,786</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
7	Plant Unit Info	75.0	11,786	21.0%	N/A	21.0%	N/A						
8	Barefoot PV Solar												
9	Solar		<u>11,620</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
10	Plant Unit Info	75.0	11,620	21.0%	N/A	21.0%	N/A						
11	Blue Cypress PV Solar												
12	Solar		<u>12,043</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
13	Plant Unit Info	75.0	12,043	22.0%	N/A	22.0%	N/A						
14	Blue Heron ST Solar												
15	Solar		<u>12,564</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
16	Plant Unit Info	75.0	12,564	23.0%	N/A	23.0%	N/A						
17	Cape Canaveral 3												
18	Light Oil		0				0	0	0	0	0	0.00	0.00
19	Gas		<u>0</u>					0	0	<u>0</u>	<u>0</u>	<u>0.00</u>	0.00
20	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
21	Cattle Ranch ST Solar												
22	Solar		<u>10,595</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
23	Plant Unit Info	75.0	10,595	19.0%	N/A	19.0%	N/A						
24	CCEC 3												
25	Gas		<u>377,651</u>				6,730	2,541,634	1,000,000	<u>2,541,634</u>	<u>15,646,048</u>	<u>4.14</u>	6.16
26	Plant Unit Info	1,326.0	377,651	38.0%	93.0%	41.0%	6,730			<u>2,541,634</u>	<u>15,646,048</u>	<u>4.14</u>	
27	Citrus PV Solar												
28	Solar		<u>11,757</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
29	Plant Unit Info	75.0	11,757	21.0%	N/A	21.0%	N/A						
30	Coral Farms PV Solar												
31	Solar		<u>12,061</u>					N/A	N/A	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	N/A
32	Plant Unit Info	75.0	12,061	22.0%	N/A	22.0%	N/A						
33	Dania Beach												
34	Light Oil		0				0	0	0	0	0	0.00	0.00
35	Gas		0					0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
2	Desoto Solar												
3	Solar		2,906					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	25.0	2,906	16.0%	N/A	16.0%	N/A						
5	Discovery PV Solar												
6	Solar		9,342					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	75.0	9,342	17.0%	N/A	17.0%	N/A						
8	Echo River PV Solar												
9	Solar		10,814					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	75.0	10,814	20.0%	N/A	20.0%	N/A						
11	Egret PV Solar												
12	Solar		8,172					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	75.0	8,172	15.0%	N/A	15.0%	N/A						
14	Elder Branch PV Solar												
15	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
17	Fort Drum PV Solar												
18	Solar		9,111					N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	75.0	9,111	16.0%	N/A	16.0%	N/A						
20	Fort Myers 2												
21	Gas		756,382				6,992	5,288,828	1,000,000	5,288,828	32,553,766	4.30	6.16
22	Plant Unit Info	1,740.0	756,382	58.0%	85.0%	69.0%	6,992			5,288,828	32,553,766	4.30	
23	Fort Myers 3A												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	189.0	0	N/A	94.0%	N/A	N/A						
27	Fort Myers 3B												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	193.0	0	N/A	94.0%	N/A	N/A						
31	Fort Myers 3C												
32	Light Oil		0				0	0	0	0	0	0.00	0.00
33	Gas		3,974				10,686	42,468	1,000,000	42,468	262,243	6.60	6.18
34	Plant Unit Info	221.0	3,974	2.0%	94.0%	3.0%	10,686			42,468	262,243	6.60	
35	Fort Myers 3D												

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Light Oil		0				0	0	0	0	0	0.00	0.00
2	Gas		2,798				10,994	30,762	1,000,000	30,762	189,799	6.78	6.17
3	Plant Unit Info	221.0	2,798	2.0%	94.0%	2.0%	10,994			30,762	189,799	6.78	
4	Fort Myers GT												
5	Light Oil		0				0	0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Ghost Orchid PV Solar												
8	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
9	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
10	Grove PV Solar												
11	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
13	Hammock PV Solar												
14	Solar		12,892					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	75.0	12,892	23.0%	N/A	23.0%	N/A						
16	Hibiscus PV Solar												
17	Solar		11,247					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	11,247	20.0%	N/A	20.0%	N/A						
19	Horizon PV Solar												
20	Solar		12,148					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	12,148	22.0%	N/A	22.0%	N/A						
22	Immokalee PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Indian River PV Solar												
26	Solar		12,031					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	12,031	22.0%	N/A	22.0%	N/A						
28	Indiantown FPL												
29	Coal											N/A	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
32	Interstate PV Solar												
33	Solar		11,611					N/A	N/A	N/A	N/A	N/A	N/A
34	Plant Unit Info	75.0	11,611	21.0%	N/A	21.0%	N/A						
35	Lakeside PV Solar												

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Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Solar		10,447					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	75.0	10,447	19.0%	N/A	19.0%	N/A						
3	Lauderdale 1-12												
4	Light Oil		0				0	0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
7	Lauderdale 6A												
8	Light Oil		0				0	0	0	0	0	0.00	0.00
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
11	Lauderdale 6B												
12	Light Oil		0				0	0	0	0	0	0.00	0.00
13	Gas		1,913				10,860	20,775	1,000,000	20,775	128,451	6.71	6.18
14	Plant Unit Info	218.0	1,913	1.0%	94.0%	1.0%	10,860			20,775	128,451	6.71	
15	Lauderdale 6C												
16	Light Oil		0				0	0	0	0	0	0.00	0.00
17	Gas		1,013				10,585	10,723	1,000,000	10,723	66,132	6.53	6.17
18	Plant Unit Info	218.0	1,013	1.0%	94.0%	1.0%	10,585			10,723	66,132	6.53	
19	Lauderdale 6D												
20	Light Oil		0				0	0	0	0	0	0.00	0.00
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
23	Lauderdale 6E												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
27	Loggerhead PV Solar												
28	Solar		12,343					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	12,343	22.0%	N/A	22.0%	N/A						
30	Magnolia PV Solar												
31	Solar		8,228					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	8,228	15.0%	N/A	15.0%	N/A						
33	Manatee 1												
34	Heavy Oil											N/A	0.00
35	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
2	Manatee 2												
3	Heavy Oil											N/A	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
6	Manatee 3												
7	Gas		233,750				6,954	1,625,400	1,000,000	1,625,400	9,891,888	4.23	6.09
8	Plant Unit Info	1,254.0	233,750	25.0%	49.0%	51.0%	6,954			1,625,400	9,891,888	4.23	
9	Manatee PV Solar												
10	Solar		11,751					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	11,751	21.0%	N/A	21.0%	N/A						
12	Martin 3												
13	Gas		174,229				7,350	1,280,653	1,000,000	1,280,653	7,794,984	4.47	6.09
14	Plant Unit Info	492.0	174,229	48.0%	94.0%	51.0%	7,350			1,280,653	7,794,984	4.47	
15	Martin 4												
16	Gas		38,943				7,653	298,026	1,000,000	298,026	1,813,733	4.66	6.09
17	Plant Unit Info	492.0	38,943	11.0%	94.0%	11.0%	7,653			298,026	1,813,733	4.66	
18	Martin 8												
19	Light Oil		0				0	0	0	0	0	0.00	0.00
20	Gas		221,438				6,991	1,548,165	1,000,000	1,548,165	9,424,049	4.26	6.09
21	Plant Unit Info	1,258.0	221,438	24.0%	94.0%	25.0%	6,991			1,548,165	9,424,049	4.26	
22	Martin 8 Solar												
23	Solar		5,425					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	55.0	5,425	13.0%	N/A	13.0%	N/A						
25	Miami-Dade PV Solar												
26	Solar		12,413					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	12,413	22.0%	N/A	22.0%	N/A						
28	Nassau PV Solar												
29	Solar		7,747					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	7,747	14.0%	N/A	14.0%	N/A						
31	Northern Preserve ST Solar												
32	Solar		10,920					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	10,920	20.0%	N/A	20.0%	N/A						
34	OKEECHOBEE 1												
35	Light Oil		0				0	0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		725,283				6,375	4,623,627	1,000,000	4,623,627	28,719,017	3.96	6.21
2	Plant Unit Info	1,640.0	725,283	59.0%	78.0%	76.0%	6,375			4,623,627	28,719,017	3.96	
3	Okeechobee PV Solar												
4	Solar		11,539					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	75.0	11,539	21.0%	N/A	21.0%	N/A						
6	Orange Blossom PV Solar												
7	Solar		10,031					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	75.0	10,031	18.0%	N/A	18.0%	N/A						
9	Palm Bay PV Solar												
10	Solar		9,871					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	9,871	18.0%	N/A	18.0%	N/A						
12	PEEC												
13	Light Oil		0				0	0	0	0	0	0.00	0.00
14	Gas		730,134				6,424	4,690,332	1,000,000	4,690,332	28,870,748	3.95	6.16
15	Plant Unit Info	1,283.0	730,134	76.0%	93.0%	82.0%	6,424			4,690,332	28,870,748	3.95	
16	Pelican PV Solar												
17	Solar		10,031					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	75.0	10,031	18.0%	N/A	18.0%	N/A						
19	Pioneer Trail PV Solar												
20	Solar		11,197					N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	75.0	11,197	20.0%	N/A	20.0%	N/A						
22	Riviera 5												
23	Light Oil		0				0	0	0	0	0	0.00	0.00
24	Gas		438,708				6,690	2,935,157	1,000,000	2,935,157	18,230,157	4.16	6.21
25	Plant Unit Info	1,326.0	438,708	44.0%	93.0%	48.0%	6,690			2,935,157	18,230,157	4.16	
26	Rodeo PV Solar												
27	Solar		9,474					N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	75.0	9,474	17.0%	N/A	17.0%	N/A						
29	Sabal Palm PV Solar												
30	Solar		10,439					N/A	N/A	N/A	N/A	N/A	N/A
31	Plant Unit Info	75.0	10,439	19.0%	N/A	19.0%	N/A						
32	Sanford 4												
33	Gas		58,740				7,495	440,277	1,000,000	440,277	2,717,217	4.63	6.17
34	Plant Unit Info	1,192.0	58,740	7.0%	94.0%	7.0%	7,495			440,277	2,717,217	4.63	
35	Sanford 5												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Gas		419,229				6,950	2,913,813	1,000,000	2,913,813	17,934,261	4.28	6.15
2	Plant Unit Info	1,192.0	419,229	47.0%	94.0%	50.0%	6,950			2,913,813	17,934,261	4.28	
3	Sawgrass PV Solar												
4	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
6	Scherer 4												
7	Light Oil		0				0	0	0	0	0	0.00	0.00
8	Coal		235,935				11,055	153,430	17,000,000	2,608,309	6,740,833	2.86	43.93
9	Plant Unit Info	626.0	235,935	51.0%	92.0%	55.0%	11,055			2,608,309	6,740,833	2.86	
10	Southfork PV Solar												
11	Solar		12,295					N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	75.0	12,295	22.0%	N/A	22.0%	N/A						
13	Space Coast												
14	Solar		1,170					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	10.0	1,170	16.0%	100.0%	16.0%	N/A						
16	St Lucie 1												
17	Nuclear		727,591				10,328	7,514,787	1,000,000	7,514,787	3,654,441	0.50	0.49
18	Plant Unit Info	1,003.0	727,591	98.0%	98.0%	100.0%	10,328			7,514,787	3,654,441	0.50	
19	St Lucie 2												
20	Nuclear		623,512				10,257	6,395,178	1,000,000	6,395,178	2,732,020	0.44	0.43
21	Plant Unit Info	860.0	623,512	98.0%	98.0%	100.0%	10,257			6,395,178	2,732,020	0.44	
22	Sundew PV Solar												
23	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
24	Plant Unit Info	0	0	N/A	N/A	N/A	N/A						
25	Sunshine Gateway PV Solar												
26	Solar		10,864					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	75.0	10,864	20.0%	N/A	20.0%	N/A						
28	Sweetbay PV Solar												
29	Solar		10,858					N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	75.0	10,858	20.0%	N/A	20.0%	N/A						
31	Trailside PV Solar												
32	Solar		8,552					N/A	N/A	N/A	N/A	N/A	N/A
33	Plant Unit Info	75.0	8,552	15.0%	N/A	15.0%	N/A						
34	Turkey Point 3												
35	Nuclear		623,100				10,541	6,568,284	1,000,000	6,568,284	3,258,526	0.52	0.50

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost (\$)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel (\$/Unit)
1	Plant Unit Info	859.0	623,100	98.0%	98.0%	100.0%	10,541			6,568,284	3,258,526	0.52	
2	Turkey Point 4												
3	Nuclear		628,234				10,456	6,568,874	1,000,000	6,568,874	3,890,087	0.62	0.59
4	Plant Unit Info	866.0	628,234	98.0%	98.0%	100.0%	10,456			6,568,874	3,890,087	0.62	
5	Turkey Point 5												
6	Light Oil		0				0	0	0	0	0	0.00	0.00
7	Gas		462,393				6,883	3,182,708	1,000,000	3,182,708	19,589,636	4.24	6.16
8	Plant Unit Info	1,294.0	462,393	48.0%	73.0%	66.0%	6,883			3,182,708	19,589,636	4.24	
9	Twin Lakes ST Solar												
10	Solar		10,310					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	10,310	19.0%	N/A	19.0%	N/A						
12	Union Springs PV Solar												
13	Solar		8,322					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	75.0	8,322	15.0%	N/A	15.0%	N/A						
15	WCEC 01												
16	Light Oil		0				0	0	0	0	0	0.00	0.00
17	Gas		348,422				6,812	2,373,566	1,000,000	2,373,566	14,445,086	4.15	6.09
18	Plant Unit Info	1,248.0	348,422	38.0%	94.0%	40.0%	6,812			2,373,566	14,445,086	4.15	
19	WCEC 02												
20	Light Oil		0				0	0	0	0	0	0.00	0.00
21	Gas		511,076				6,759	3,454,425	1,000,000	3,454,425	21,022,996	4.11	6.09
22	Plant Unit Info	1,248.0	511,076	55.0%	94.0%	59.0%	6,759			3,454,425	21,022,996	4.11	
23	WCEC 03												
24	Light Oil		0				0	0	0	0	0	0.00	0.00
25	Gas		351,572				6,760	2,376,603	1,000,000	2,376,603	14,463,570	4.11	6.09
26	Plant Unit Info	1,254.0	351,572	38.0%	56.0%	67.0%	6,760			2,376,603	14,463,570	4.11	
27	Wildflower PV Solar												
28	Solar		12,684					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	75.0	12,684	23.0%	N/A	23.0%	N/A						
30	Willow PV Solar												
31	Solar		9,726					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	75.0	9,726	18.0%	N/A	18.0%	N/A						
33	System Totals												
34	Plant Unit Info	28,976	9,127,922				7,596			69,333,374	264,039,686	2.89	N/A
35	Total												

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE E5

ESTIMATED FOR THE PERIOD OF: AUGUST 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Fuel Type	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021
1	#6 Heavy Oil (BBLs)					
2	Purchases					
3	Units					
4	Unit Cost					
5	Amount					
6	Burned					
7	Units	25,204	35,679	21,598		
8	Unit Cost	74.8961	74.8961	74.8961		
9	Amount	1,887,650	2,672,186	1,617,580		
10	Ending Inventory					
11	Units	533,096	497,418	475,820	475,820	475,820
12	Unit Cost	74.8961	74.8961	74.8961	74.8961	74.8961
13	Amount	39,926,825	37,254,639	35,637,059	35,637,059	35,637,059
14						
15	#2 Light Oil (BBLs)					
16	Purchases					
17	Units			32,851		
18	Unit Cost			95.3508		
19	Amount			3,132,339		
20	Burned					
21	Units	5,725	18,191	7,486		
22	Unit Cost	76.3716	77.5228	95.0463		
23	Amount	437,205	1,410,237	711,559		
24	Ending Inventory					
25	Units	1,378,042	1,359,851	1,385,215	1,385,215	1,385,215
26	Unit Cost	92.2190	92.4156	92.4710	92.4710	92.4710
27	Amount	127,081,729	125,671,492	128,092,272	128,092,272	128,092,272
28						
29	Coal					
30	Purchases					
31	Units	2,000,000	2,250,000	2,300,000	2,300,000	2,164,848
32	Unit Cost	2.5717	2.5621	2.5668	2.5763	2.5859
33	Amount	5,143,400	5,764,725	5,903,640	5,925,490	5,598,080
34	Burned					
35	Units	2,966,527	2,801,894	2,534,628	2,454,674	2,608,309
36	Unit Cost	2.6967	2.6134	2.5792	2.5769	2.5844
37	Amount	7,999,883	7,322,424	6,537,270	6,325,437	6,740,833
38	Ending Inventory					
39	Units	1,384,657	832,763	598,135	443,461	
40	Unit Cost	2.6967	2.6134	2.5792	2.5769	0.0000
41	Amount	3,734,028	2,176,329	1,542,699	1,142,752	(0)
42						
43	Gas (MMBTU)					
44	Burned					
45	Units	62,021,350	59,966,913	53,584,351	41,255,868	39,677,942
46	Unit Cost	5.3527	5.2456	5.4386	5.8667	6.1436
47	Amount	331,980,872	314,560,912	291,424,881	242,035,401	243,763,779
48						
49	Nuclear (Other)					
50	Burned					
51	Units	26,221,278	19,985,311	21,966,592	24,903,353	27,047,123
52	Unit Cost	0.4977	0.5145	0.4982	0.4986	0.5004
53	Amount	13,050,373	10,281,457	10,944,257	12,417,597	13,535,074
54						

APPENDIX III-B

REVISED 2021 GULF FCR ACTUAL/ESTIMATED TRUE-UP

RBD-6
DOCKET NO. 20210001-EI
FPL WITNESS: RENAE B. DEATON
EXHIBIT _____
PAGES 1-14
SEPTEMBER 3, 2021

APPENDIX III-B

**REVISED 2021 GULF FCR ACTUAL/ESTIMATED TRUE-UP
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3-4	Schedule E3 Generating System Comparative Data by Fuel Type	G. J. Yupp
5-10	Schedule E4 System Net Generation and Fuel Costs	G. J. Yupp
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13-14	Schedule E9 Economy Energy Purchases	G. J. Yupp

Schedule E-1A

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP

TO BE INCLUDED IN THE PERIOD JANUARY 2021 - DECEMBER 2021

(1) Line No.	(2) Description	(3) Total
1.	Estimated over/(under)-recovery for the period January 2021 - December 2021 (Sch. E-1B, line C9)	\$ (71,727,041)
2.	Final over/(under)-recovery for the period January 2020 - December 2020 (Exhibit RLH-1, Schedule 1, line 3)	\$ 6,085,680
3.	Total over/(under)-recovery (Lines 1 + 2) ⁽¹⁾ To be included in January 2022 - December 2022	\$ (65,641,362)
4.	Jurisdictional kWh sales for the period January 2022 - December 2022	10,843,037,000
5.	True-Up Factor (Line 3/Line 4) x 100(¢/kWh)	0.6054

GULF POWER COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL FOR THE PERIOD JANUARY 2021 - JULY 2021 / ESTIMATED FOR AUGUST 2021 - DECEMBER 2021

		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total Period	
A	1	Fuel Cost of System Generation	21,380,372.00	28,880,778.57	16,752,942.96	15,418,156.98	16,068,473.61	23,133,599.45	32,775,409.89	35,615,470.00	34,895,787.00	27,364,221.00	28,651,148.00	23,991,175.00	304,927,534.46
	1a	Fuel Cost of Hedging Settlement	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	1b	Wholesale kWh Sales Credit	(632,992.40)	(1,012,727.67)	(494,001.74)	(449,863.20)	(671,041.17)	(858,321.4)	(1,077,943.7)	(865,188.1)	(767,986.5)	(648,648.1)	(618,312.5)	(728,328.5)	(8,825,355.00)
	2	Fuel Cost of Power Sold	(10,784,812.81)	(12,361,914.90)	(8,401,282.21)	(1,425,250.20)	(2,625,204.74)	(4,906,523.34)	(9,137,071.48)	(12,511,824.00)	(12,818,118.00)	(4,418,633.00)	(10,062,985.00)	(8,307,275.00)	(97,760,894.68)
	3	Fuel Cost of Purchased Power	15,678,283.20	14,664,962.88	17,380,602.79	13,495,940.72	14,988,416.40	18,523,921.70	20,084,904.57	21,707,101.00	22,461,357.00	13,492,043.00	13,495,244.00	16,617,623.00	202,590,399.96
	3a	Demand & Non-Fuel Cost of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	241,980.69	283,198.03	186,301.01	303,834.60	279,402.30	439,568.59	476,919.39	0.00	0.00	0.00	0.00	0.00	2,211,204.61
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	211,836.04	273,941.62	213,193.01	221,110.52	170,206.98	166,914.86	180,561.55	157,259.00	152,193.00	157,259.00	152,193.00	157,259.00	2,213,927.58
	6	Adjustments to Fuel Cost	(66,102.18)	(56,447.68)	(168,779.16)	259,204.59	0.00	0.00	(101,085.40)	0.00	0.00	0.00	0.00	0.00	(133,209.83)
	7	TOTAL FUEL & NET POWER TRANSACTIONS	26,028,564.54	30,671,790.85	25,468,976.66	27,823,134.01	28,210,253.38	36,499,159.82	43,201,694.85	44,102,817.93	43,923,232.49	35,946,241.87	31,617,287.51	31,730,453.49	405,223,607.10
B	1	Jurisdictional kWh Sales	845,524,629	770,762,557	740,914,413	725,199,507	921,217,470	1,028,037,836	1,141,843,782	1,140,336,000	1,077,518,000	916,091,000	760,923,000	784,724,000	10,853,092,194
	2	Non-Jurisdictional kWh Sales	25,558,119	22,278,124	21,218,738	19,563,377	24,843,492	28,026,888	30,167,824	28,492,000	25,291,000	21,361,000	20,362,000	23,985,000	291,147,562
	3	TOTAL SALES (Lines B1 + B2)	871,082,748	793,040,681	762,133,151	744,762,884	946,060,962	1,056,064,724	1,172,011,606	1,168,828,000	1,102,809,000	937,452,000	781,285,000	808,709,000	11,144,239,756
	4	Jurisdictional % of Total Sales (Line B1/B3)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
C	1	Jurisdictional Fuel Recovery Revenue (1) (Net of Revenue Taxes)	25,464,396.75	23,376,454.61	22,454,383.99	21,752,113.59	27,873,520.51	32,769,548.06	37,457,616.05	34,789,409.71	32,872,956.01	27,948,135.57	23,214,264.92	23,940,386.64	333,913,186.41
	2	True-Up Provision	(91,639.00)	(91,641.00)	(91,641.00)	(91,641.00)	(91,641.00)	(91,641.00)	(91,641.00)	(91,641.00)	(91,641.00)	(91,641.00)	(91,641.00)	(91,641.00)	(1,099,690.00)
	2a	Incentive Provision	(5,185.00)	(5,182.00)	(5,182.00)	(5,182.00)	(5,182.00)	(5,182.00)	(5,182.00)	(5,182.00)	(5,182.00)	(5,182.00)	(5,182.00)	(5,182.00)	(62,187.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD	25,367,572.75	23,279,631.61	22,357,560.99	21,655,290.59	27,776,697.51	32,672,725.06	37,360,793.05	34,692,586.71	32,776,133.01	27,851,312.57	23,117,441.92	23,843,563.64	332,751,309.41
	4	Fuel & Net Power Transactions (Line A7)	26,028,564.54	30,671,790.85	25,468,976.66	27,823,134.01	28,210,253.38	36,499,159.82	43,201,694.85	44,102,817.93	43,923,232.49	35,946,241.87	31,617,287.51	31,730,453.49	405,223,607.10
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0012)	26,059,798.82	30,708,597.00	25,499,539.43	27,856,521.77	28,244,105.68	36,542,958.81	43,253,536.88	44,155,741.31	43,975,940.37	35,989,377.36	31,655,228.25	31,768,530.03	405,709,875.71
	6	Over/(Under) Recovery (Line C3-C5)	(692,226.07)	(7,428,965.39)	(3,141,978.44)	(6,201,231.18)	(467,408.17)	(3,870,233.75)	(5,892,743.83)	(9,463,154.60)	(11,199,807.36)	(8,138,064.79)	(8,537,786.33)	(7,924,966.39)	(72,958,566.30)
	7	Interest Provision	376.89	139.32	(268.21)	(585.87)	(508.53)	(656.63)	(1,039.54)	(1,275.52)	(1,787.58)	(2,266.53)	(2,678.96)	(3,086.08)	(13,637.24)
	8	Adjustments	1,245,162.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,245,162.08
	9	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2021 - DECEMBER 2021													(\$71,727,041.46)

* (Gain)/Loss on sales of natural gas and contract dispute litigation

Notes 1: Projected Revenues based on the current approved 2021 Fuel Factor excluding revenue taxes of:
Total may not add due to rounding

3.0508 ¢/KWH

GULF POWER COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD JANUARY 2021 - JULY 2021 / ESTIMATED FOR AUGUST 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	TOTAL
FUEL COST - NET GEN. (\$)														
1	LIGHTER OIL (B.L.)	29,515	126,543	43,804	13,951	83,681	31,780	21,756	0	0	0	0	0	351,030
2	COAL	4,563,261	3,936,182	3,795,698	8,127,582	1,581,822	3,206,283	3,670,071	4,610,737	4,544,657	4,470,683	8,178,320	9,108,996	59,794,291
2a	Coal at Scherer	(154,910)	1,030,156	(7,252)	(213,141)	459,962	1,700,469	3,045,431	3,388,363	3,231,519	1,516,388	1,097,548	993,184	16,087,716
3	GAS - Generation	17,072,292	23,972,501	13,055,842	7,404,301	13,973,417	18,257,819	26,131,927	27,692,932	27,193,647	21,453,712	19,449,316	13,965,557	229,623,263
4	GAS (B.L.)	3,414	22,476	0	221,071	38,903	22,380	11,645	0	0	0	0	0	319,889
5	Landfill Gas	78,636	62,900	78,043	66,610	100,896	75,142	75,142	80,697	78,157	80,697	78,157	80,697	935,775
6	OIL - C.T.	0	3,963	0	18,895	0	6,641	0	0	0	0	0	0	29,499
7	TOTAL (\$)	21,592,208	29,154,720	16,966,136	15,639,268	16,238,681	23,300,514	32,955,971	35,772,729	35,047,980	27,521,480	28,803,341	24,148,434	307,141,462
SYSTEM NET GEN. (MWH)														
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL	151,160	134,550	117,976	152,745	92,510	110,598	126,353	166,045	165,724	164,373	304,584	342,396	2,029,014
9a	Coal at Scherer	(688)	33,444	(702)	(699)	12,537	45,472	92,576	106,341	107,429	50,794	36,986	34,011	517,501
10	GAS	698,726	636,595	554,758	278,325	486,502	564,904	670,191	775,400	723,378	599,649	572,801	369,539	6,930,769
11	Landfill Gas	2,130	1,729	2,153	1,871	2,135	1,992	2,189	2,097	2,031	2,097	2,031	2,097	24,552
12	OIL - C.T.	(9)	37	(9)	35	(11)	16	(11)	0	0	0	0	0	48
13	Solar	9,178	8,954	14,463	15,710	19,677	15,530	15,489	18,294	16,424	15,891	12,454	9,851	171,915
14	TOTAL (MWH)	860,497	815,309	688,639	447,987	613,350	738,513	906,788	1,068,177	1,014,986	832,804	928,856	757,894	9,673,799
UNITS OF FUEL BURNED														
15	LIGHTER OIL (BBL)	470	1,799	635	199	1,042	339	0	0	0	0	0	0	4,484
16	COAL excl. Scherer (TON) (2)	93,432	79,999	78,184	97,514	54,648	67,706	81,888	91,511	91,834	91,571	169,388	190,901	1,188,576
17	GAS-all (MCF) (1)	5,470,962	5,581,376	3,943,029	2,262,833	3,629,258	4,622,799	6,604,362	6,713,115	6,233,575	4,725,784	4,499,403	3,082,404	57,368,900
18	OIL - C.T. (BBL)	0	45	0	214	0	75	0	0	0	0	0	0	334
BTU'S BURNED (MMBTU)														
19	COAL + GAS B.L. + OIL B.L.	1,604,868	1,818,600	1,370,268	1,693,919	1,144,957	1,741,501	2,424,470	2,778,845	2,794,087	2,202,646	3,438,979	3,783,927	26,797,067
20	GAS-Generation (1)	5,620,810	5,731,545	4,052,271	2,250,122	3,715,975	4,740,372	6,604,362	6,713,115	6,233,575	4,725,784	4,499,403	3,082,404	57,969,738
21	OIL - C.T.	0	262	0	1,244	0	436	0	0	0	0	0	0	1,942
22	TOTAL (MMBTU)	7,225,678	7,550,407	5,422,539	3,945,285	4,860,932	6,482,309	9,028,832	9,491,960	9,027,662	6,928,430	7,938,382	6,866,331	84,768,747

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

(2) Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and \$ only.

GULF POWER COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD JANUARY 2021 - JULY 2021 / ESTIMATED FOR AUGUST 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	TOTAL
GENERATION MIX (% MWH)														
23	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	COAL	17.49	20.60	17.03	33.94	17.13	21.13	24.14	25.49	26.90	25.83	36.77	49.65	26.32
25	GAS-Generation	81.19	78.09	80.56	62.12	79.31	76.50	73.91	72.60	71.28	72.01	61.67	48.76	71.65
26	Landfill Gas	0.25	0.21	0.31	0.42	0.35	0.27	0.24	0.20	0.20	0.25	0.22	0.29	0.25
27	OIL - C.T.	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Solar	1.07	1.10	2.10	3.51	3.21	2.10	1.71	1.71	1.62	1.91	1.34	1.30	1.78
29	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST \$ / UNIT														
30	LIGHTER OIL (\$/BBL)	62.80	70.34	68.98	70.10	80.31	93.89	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	78.29
31	COAL (\$/TON) (2)	48.84	49.20	48.55	83.35	28.95	47.36	44.82	50.38	49.49	48.82	48.28	47.72	50.31
32	GAS + B.L. (\$/MCF) (1)	3.07	4.25	3.26	3.27	3.81	3.92	3.93	4.10	4.34	4.51	4.29	4.48	3.97
33	OIL - C.T.	0.00	88.06	0.00	88.29	0.00	88.55	0.00	0.00	0.00	0.00	0.00	0.00	88.32
FUEL COST \$ / MMBTU														
34	COAL + GAS B.L. + OIL B.L.	2.86	2.57	2.80	4.94	2.10	2.85	2.78	2.88	2.78	2.72	2.70	2.67	2.86
35	GAS-Generation (1)	3.00	4.13	3.17	3.19	3.71	3.82	3.93	4.10	4.34	4.51	4.29	4.48	3.92
36	OIL - C.T.	0.00	15.12	0.00	15.19	0.00	15.23	0.00	0.00	0.00	0.00	0.00	0.00	15.19
37	TOTAL (\$/MMBTU)	2.95	3.82	3.08	3.89	3.28	3.56	3.62	3.74	3.86	3.94	3.60	3.48	3.59
BTU BURNED BTU / KWH														
38	COAL + GAS B.L. + OIL B.L.	10,666	10,825	11,684	11,141	10,899	11,158	11,074	10,202	10,229	10,237	10,068	10,053	10,523
39	GAS-Generation (1)	8,140	9,126	7,422	8,341	7,733	8,475	9,939	8,722	8,684	7,957	7,932	8,472	8,461
40	OIL - C.T.	0	7,081	0	35,543	0	27,250	0	0	0	0	0	0	40,458
41	TOTAL (BTU/KWH)	8,500	9,379	8,001	9,017	8,032	8,868	10,043	8,952	8,961	8,398	8,617	9,154	8,858
FUEL COST CENTS / KWH														
42	COAL + GAS B.L. + OIL B.L.	2.95	3.04	3.27	5.36	2.06	3.18	3.08	2.94	2.85	2.78	2.72	2.68	3.01
43	GAS-Generation	2.44	3.77	2.35	2.66	2.87	3.23	3.90	3.57	3.76	3.58	3.40	3.78	3.31
44	Landfill Gas	3.69	3.64	3.62	3.56	4.73	3.77	3.43	3.85	3.85	3.85	3.85	3.85	3.81
45	OIL - C.T.	0.00	10.71	0.00	53.99	0.00	41.51	0.00	0.00	0.00	0.00	0.00	0.00	61.46
46	TOTAL (¢/KWH)	2.51	3.58	2.46	3.49	2.65	3.16	3.63	3.35	3.45	3.30	3.10	3.19	3.17

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

(2) Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and \$ only.

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: JULY 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78	0	0.0%	100.0%	0.0%	N/A						
2	Gas-G		(299)					-	-	-	-	0.00	0.00
3	Gas-S							-	-	-	-	0.00	0.00
4	Oil-S							-	139,075	-	-	0.00	0.00
5	GCEC 5 ⁽⁴⁾	78		0.0%	100.0%	0.0%	N/A						
6	Gas-G		(300)					-	-	-	-	0.00	0.00
7	Gas-S							-	-	-	-	0.00	0.00
8	Oil-S							-	139,075	-	-	0.00	0.00
9	GCEC 6 ⁽⁴⁾	315	0	41.3%	80.2%	41.3%	12,329						
10	Gas-G		96,834					1,162,726	-	1,193,887	5,278,494	5.45	4.54
11	Gas-S		0					-	-	-	-	0.00	0.00
12	Oil-S							-	139,075	-	-	0.00	0.00
13	GCEC 7 ⁽⁴⁾	496	0	32.9%	98.3%	33.5%	12,391						
14	Gas-G		121,292					1,463,749	1,027	1,502,977	6,645,064	5.48	4.54
15	Gas-S							2,565	-	2,634	11,645	4.54	4.54
16	Oil-S							-	139,075	-	-	0.00	0.00
17	Smith 3	660	447,017	91.0%	100.0%	93.3%	7,096						
18	Gas-G							3,087,302	1,027	3,172,141	14,027,808	3.14	4.54
19	Smith A	32	(11.00)	0.0%	100.0%	0.0%	-						
20	Oil							-	-	-	-	0.00	0.00
21	Scherer 3 ⁽²⁾	215	92,576	57.9%	99.2%	57.9%	10,550						
22	Coal								8,712	976,667	3,045,431	3.29	3.12
23	Oil							35	138,500	206	3,332	0.00	95.20
24	Other Generation		5,647										
25	Gas										180,562	3.20	0.00
26	Perdido		2,189										
27	Landfill Gas										75,142	3.43	0.00
28	Blue Indigo		15,489										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	128,559	68.8%	80.4%	78.5%	10,329						
31	Coal							75,198	8,830	1,327,941	3,677,065	2.86	48.90
32	Oil-S							245	138,184	1,424	18,423	75.20	75.20
33	Daniel 2 ⁽³⁾	251	(2,206)	0.0%	0.0%	0.0%	-						
34	Coal							-	8,830	-	-	0.00	0.00
35	Oil-S							-	-	-	-	0.00	0.00
36	Gas,BL												
37	Gas							-	-	-	-	N/A	N/A
38	Ltr. Oil												
39	Oil							-	-	-	-	N/A	N/A
40	Total	2,376	906,788	51.3%	84.3%	51.9%	9,097			8,177,877	32,962,966	3.64	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Adj. Units	Adj. Description	Adj. \$	cents/kWh
N/A	Daniel Railcar Track Deprec.	(6,995)	

Recoverable Fuel **32,955,971** **3.63**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: AUGUST 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		6.6%	92.4%	9.1%	13,148						
2	Gas-G		3,841					49,513	1,020	50,503	257,678	6.71	5.20
3	Gas-S							-	-	-	-		N/A
4	Oil-S							-	-	-	-		N/A
5	GCEC 5 ⁽⁴⁾	78		45.0%	92.4%	9.1%	13,147						
6	Gas-G		26,089					336,277	1,020	343,002	1,325,563	5.08	3.94
7	Gas-S							-	-	-	-		N/A
8	Oil-S							-	-	-	-		N/A
9	GCEC 6 ⁽⁴⁾	315		43.5%	92.4%	60.6%	11,398						
10	Gas-G		101,939					1,139,096	1,020	1,161,878	4,315,197	4.23	3.79
11	Gas-S							-	-	-	-		N/A
12	Oil-S							-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	496		44.4%	92.4%	65.3%	11,180						
14	Gas-G		163,804					1,795,340	1,020	1,831,247	6,758,996	4.13	3.76
15	Gas-S							-	-	-	-		N/A
16	Oil-S							-	-	-	-		N/A
17	Smith 3	660	474,015	96.5%	93.5%	94.4%	7,018						
18	Gas-G							3,261,260	1,020	3,326,485	14,878,240	3.14	4.56
19	Smith A	32	-	0.0%	93.5%	0.0%	N/A						
20	Oil							-	-	-	-	N/A	N/A
21	Scherer 3 ⁽²⁾	215	106,341	66.5%	92.9%	9.5%	10,797						
22	Coal								8,538	1,148,119	3,388,363	3.19	N/A
23	Oil							-	-	-	-		
24	Other Generation		5,712										
25	Gas										157,259		
26	Perdido		2,097										
27	Landfill Gas										80,697		
28	Blue Indigo		18,294										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	166,045	88.9%	92.3%	23.5%	9,821						
31	Coal							91,511	9,126	1,630,726	4,610,736	2.78	50.38
32	Oil-S							-	-	-	-		
33	Daniel 2 ⁽³⁾	251	-	0.0%	60.5%	0.0%	N/A						
34	Coal							-	-	-	-	N/A	N/A
35	Oil-S							-	-	-	-		
36	Gas,BL												
37	Gas							-	-	-	-	N/A	N/A
38	Ltr. Oil												
39	Oil							-	-	-	-	N/A	N/A
40	Total	2,376	1,068,177	60.4%	89.4%	51.8%	8,886			9,491,960	35,772,730	3.35	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Adj. Units	Adj. Description	Adj. \$	cents/kWh
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Recoverable Fuel

35,772,730

3.35

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: SEPTEMBER 2021**

Schedule E-4

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf./Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78	-	0.0%	92.4%	0.0%	N/A	-	-	-	70,931	0	N/A
2	Gas-G							-	-	-	-		N/A
3	Gas-S							-	-	-	-		N/A
4	Oil-S							-	-	-	-		N/A
5	GCEC 5 ⁽⁴⁾	78	26,889	47.9%	92.4%	0.0%	13,148	346,592	1,020	353,524	1,438,114	5.35	4.15
6	Gas-G							-	-	-	-		N/A
7	Gas-S							-	-	-	-		N/A
8	Oil-S							-	-	-	-		N/A
9	GCEC 6 ⁽⁴⁾	315	97,429	43.0%	92.4%	5.6%	11,421	1,090,923	1,020	1,112,741	4,374,235	4.49	4.01
10	Gas-G							-	-	-	-		N/A
11	Gas-S							-	-	-	-		N/A
12	Oil-S							-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	496	137,083	38.4%	92.4%	61.5%	11,503	1,545,949	1,020	1,576,868	6,169,151	4.50	3.99
14	Gas-G							-	-	-	-		N/A
15	Gas-S							-	-	-	-		N/A
16	Oil-S							-	-	-	-		N/A
17	Smith 3	660	456,449	96.1%	93.5%	94.3%	6,990	3,127,884	1,020	3,190,442	14,989,023	3.28	4.79
18	Gas-G							-	-	-	-		N/A
19	Smith A	32	-	0.0%	93.5%	0.3%	N/A	-	-	-	-	N/A	N/A
20	Oil							-	-	-	-	N/A	N/A
21	Scherer 3 ⁽²⁾	215	107,429	69.4%	92.9%	10.6%	10,776	-	8,538	1,157,605	3,231,519	3.01	N/A
22	Coal							-	-	-	-		N/A
23	Oil							-	-	-	-		N/A
24	Other Generation		5,528										
25	Gas										152,193		
26	Perdido		2,031										
27	Landfill Gas										78,157		
28	Blue Indigo		16,424										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	165,725	91.7%	92.3%	1.9%	9,875	91,834	9,066	1,636,482	4,544,656	2.74	49.49
31	Coal							-	-	-	-		
32	Oil-S							-	-	-	-		
33	Daniel 2 ⁽³⁾	251	-	0.0%	60.5%	0.0%	N/A	-	-	-	-	N/A	N/A
34	Coal							-	-	-	-		
35	Oil-S							-	-	-	-		
36	Gas,BL							-	-	-	-	N/A	N/A
37	Gas							-	-	-	-	N/A	N/A
38	Ltr. Oil							-	-	-	-	N/A	N/A
39	Oil							-	-	-	-	N/A	N/A
40	Total	2,376	1,014,987	59.3%	89.4%	40.9%	8,894			9,027,662	35,047,979	3.45	

Notes:

- (1) Smith A uses lighter oil
 (2) Represents Gulf's 25% Ownership
 (3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
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Recoverable Fuel

35,047,979

3.45

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: OCTOBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78	-	0.0%	92.4%	0.0%	N/A	-	-	-	73,296	0	N/A
2	Gas-G							-	-	-	-		N/A
3	Gas-S							-	-	-	-		N/A
4	Oil-S							-	-	-	-		N/A
5	GCEC 5 ⁽⁴⁾	78	-	0.0%	92.4%	0.0%	N/A	-	-	-	73,296	0	N/A
6	Gas-G							-	-	-	-		N/A
7	Gas-S							-	-	-	-		N/A
8	Oil-S							-	-	-	-		N/A
9	GCEC 6 ⁽⁴⁾	315	6,300	2.7%	92.4%	0.0%	11,423	70,556	1,020	71,967	351,831	5.58	4.99
10	Gas-G							-	-	-	-		N/A
11	Gas-S							-	-	-	-		N/A
12	Oil-S							-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	496	125,819	34.1%	92.4%	42.5%	11,772	1,452,093	1,020	1,481,134	5,805,730	4.61	4.00
14	Gas-G							-	-	-	-		N/A
15	Gas-S							-	-	-	-		N/A
16	Oil-S							-	-	-	-		N/A
17	Smith 3	646	461,818	96.1%	93.5%	75.1%	6,870	3,110,473	1,020	3,172,683	14,992,300	3.25	4.82
18	Gas-G							-	-	-	-		N/A
19	Smith A	40	-	0.0%	93.5%	0.3%	N/A	-	-	-	-	N/A	N/A
20	Oil							-	-	-	-		N/A
21	Scherer 3 ⁽²⁾	215	50,794	31.8%	92.9%	6.1%	11,239	-	8,539	570,851	1,516,388	2.99	N/A
22	Coal							-	-	-	-		N/A
23	Oil							-	-	-	-		N/A
24	Other Generation		5,712										
25	Gas										157,259		
26	Perdido		2,097										
27	Landfill Gas										80,697		
28	Blue Indigo		15,891										
29	Solar												
30	Daniel 1 ⁽³⁾	251	164,373	88.0%	92.3%	0.0%	9,927	91,571	9,021	1,631,795	4,470,683	2.72	48.82
31	Coal							-	-	-	-		
32	Oil-S							-	-	-	-		
33	Daniel 2 ⁽³⁾	251	-	0.0%	60.5%	0.0%	N/A	-	-	-	-	N/A	N/A
34	Coal							-	-	-	-		
35	Oil-S							-	-	-	-		
36	Gas,BL							-	-	-	-	N/A	N/A
37	Gas							-	-	-	-	N/A	N/A
38	Ltr. Oil							-	-	-	-	N/A	N/A
39	Oil							-	-	-	-	N/A	N/A
40	Total	2,370	832,804	47.2%	89.4%	29.9%	8,319			6,928,430	27,521,480	3.30	

Notes:

- (1) Smith A uses lighter oil
 (2) Represents Gulf's 25% Ownership
 (3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
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Recoverable Fuel

27,521,480

3.30

Schedule E-4

Schedule E-4

Notes:

- (1) Smith A uses lighter oil
- (2) Represents Gulf's 25% Ownership
- (3) Represents Gulf's 50% Ownership

Recoverable Fuel	28,803,342	3.10
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Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		0.0%	92.4%	0.0%	N/A						
2	Gas-G		-					-	-	-	73,296	0	N/A
3	Gas-S							-	-	-	-		N/A
4	Oil-S							-	-	-	-		N/A
5	GCEC 5 ⁽⁴⁾	78		0.0%	92.4%	0.0%	N/A						
6	Gas-G		-					-	-	-	73,296	0	N/A
7	Gas-S							-	-	-	-		N/A
8	Oil-S							-	-	-	-		N/A
9	GCEC 6 ⁽⁴⁾	315		20.5%	92.4%	30.6%	11,423						
10	Gas-G		48,020					537,795	1,020	548,551	2,286,755	4.76	4.25
11	Gas-S							-	-	-	-		N/A
12	Oil-S							-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	496		19.6%	92.4%	30.6%	11,772						
14	Gas-G		72,359					835,109	1,020	851,811	3,510,439	4.85	4.20
15	Gas-S							-	-	-	-		N/A
16	Oil-S							-	-	-	-		N/A
17	GCEC 8 ⁽⁴⁾	950		0.7%	92.4%	30.6%	9,986						
18	Gas-G		4,768					46,680	1,020	47,613	192,123	4.03	4.12
19	Gas-S							-	-	-	-		N/A
20	Oil-S							-	-	-	-		N/A
21	Smith 3	646	238,680	49.7%	93.5%	91.9%	6,848						
22	Gas-G							1,602,382	1,020	1,634,429	7,672,387	3.21	4.79
23	Smith A	40	-	0.0%	93.5%	0.0%	N/A						
24	Oil							-	-	-	-	N/A	N/A
25	Scherer 3 ⁽²⁾	215	34,011	21.3%	92.9%	0.0%	11,234						
26	Coal								8,538	382,071	993,184	2.92	N/A
27	Oil							-	-	-	-		
28	Other Generation		5,712										
29	Gas										157,259		
30	Perdido		2,097										
31	Landfill Gas										80,697		
32	Blue Indigo		9,851										
33	Solar										-		
34	Daniel 1 ⁽³⁾	251	169,966	91.0%	92.3%	3.6%	10,041						
35	Coal							95,328	8,951	1,706,672	4,569,877	2.69	47.94
36	Oil-S							-	-	-	-		
37	Daniel 2 ⁽³⁾	251	172,430	92.3%	60.5%	23.9%	9,831						
38	Coal							95,573	8,951	1,695,184	4,539,118	2.63	47.49
39	Oil-S							-	-	-	-		
40	Gas,BL												
41	Gas							-	-	-	-	N/A	N/A
42	Ltr. Oil												
43	Oil							-	-	-	-	N/A	N/A
44	Total	3,320	757,894	30.7%	90.2%	36.2%	9,060			6,866,331	24,148,431	3.19	

Notes:

- (1) Smith A uses lighter oil
 (2) Represents Gulf's 25% Ownership
 (3) Represents Gulf's 50% Ownership

Adj. Units	Adj. Description	Adj. \$	cents/kWh
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Recoverable Fuel

24,148,431

3.19

GULF POWER COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD JANUARY 2021 - JULY 2021 / ESTIMATED FOR AUGUST 2021 - DECEMBER 2021

(1) Line No.	(2) Description	(3) January Actual	(4) February Actual	(5) March Actual	(6) April Actual	(7) May Actual	(8) June Actual	(9) July Actual	(10) August Estimated	(11) September Estimated	(12) October Estimated	(13) November Estimated	(14) December Estimated	(15) 12 Month Period
LIGHT OIL														
1	PURCHASES :													
2	UNITS (BBL)	42	1,918	701	24	745	1,047	197	0	0	0	0	0	4,674
3	UNIT COST (\$/BBL)	343.14	77.97	88.68	559.46	94.39	96.54	92.46	0.00	0.00	0.00	0.00	0.00	91.82
4	AMOUNT (\$)	14,412	149,550	62,166	13,427	70,317	101,077	18,214	0	0	0	0	0	429,163
5	BURNED :													
6	UNITS (BBL)	470	1,799	635	199	1,052	387	386	0	0	0	0	0	4,928
7	UNIT COST (\$/BBL)	62.80	70.65	68.98	70.11	80.50	93.75	81.88	#N/A	#N/A	#N/A	#N/A	#N/A	74.46
8	AMOUNT (\$)	29,515	127,104	43,804	13,951	84,690	36,280	31,605	0	0	0	0	0	366,949
9	ENDING INVENTORY :													
10	UNITS (BBL)	7,289	7,408	7,473	7,299	6,991	7,652	7,464	7,464	7,464	7,464	7,464	7,464	
11	UNIT COST (\$/BBL)	61.96	63.99	65.89	67.39	68.30	70.87	70.86	70.86	70.86	70.86	70.86	70.86	
12	AMOUNT (\$)	451,604	474,050	492,412	491,888	477,515	542,312	528,921	528,921	528,921	528,921	528,921	528,921	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
COAL EXCLUDING PLANT SCHERER														
13	PURCHASES :													
14	UNITS (TONS)	71,681	39,477	55,657	87,807	139,815	79,768	44,345	76,000	87,500	87,500	100,000	125,000	994,550
15	UNIT COST (\$/TON)	43.28	48.91	45.72	46.15	45.38	50.18	58.18	55.37	47.03	47.03	47.03	46.98	47.83
16	AMOUNT (\$)	3,102,436	1,930,623	2,544,503	4,052,459	6,345,173	4,002,823	2,580,088	4,208,336	4,115,304	4,115,304	4,703,205	5,872,923	47,573,177
17	BURNED :													
18	UNITS (TONS)	93,432	79,999	78,184	97,514	54,648	67,706	75,198	91,511	91,834	91,571	169,388	190,901	1,181,886
19	UNIT COST (\$/TON)	48.32	48.91	48.27	47.62	46.67	47.46	48.90	50.38	49.49	48.82	48.28	47.72	48.40
20	AMOUNT (\$)	4,514,974	3,912,623	3,773,677	4,643,361	2,550,261	3,213,277	3,677,065	4,610,736	4,544,657	4,470,683	8,178,322	9,108,996	57,198,632
21	ENDING INVENTORY :													
22	UNITS (TONS)	261,501	220,979	198,452	188,745	273,912	285,974	255,121	239,610	235,276	231,205	161,817	95,916	
23	UNIT COST (\$/TON)	48.91	48.91	48.27	47.62	46.67	47.46	48.90	50.38	49.49	48.82	48.28	47.72	
24	AMOUNT (\$)	12,789,630	10,807,630	9,578,457	8,987,555	12,782,467	13,572,013	12,475,036	12,072,636	11,643,283	11,287,904	7,812,787	4,576,715	
25	DAYS SUPPLY:	29	27	25	27	25	21	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	

GULF POWER COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD JANUARY 2021 - JULY 2021 / ESTIMATED FOR AUGUST 2021 - DECEMBER 2021

(1) Line No.	(2) # Description	(3) January Actual	(4) February Actual	(5) March Actual	(6) April Actual	(7) May Actual	(8) June Actual	(9) July Actual	(10) August Estimated	(11) September Estimated	(12) October Estimated	(13) November Estimated	(14) December Estimated	(15) 12 Month Period
COAL at Plant Scherer ⁽¹⁾														
1	PURCHASES :													
2	UNITS (MMBTU)	469,650	(690,447)	1,117,553	647,595	(1,613,562)	(634,529)	349,308	645,067	655,302	663,213	724,310	659,794	2,993,254
3	UNIT COST (\$/MMBTU)	2.71	2.69	2.86	3.30	2.58	2.45	2.88	2.57	2.56	2.57	2.58	2.59	2.89
4	AMOUNT (\$)	1,274,249	(1,854,014)	3,201,017	2,136,644	(4,158,041)	(1,556,318)	1,004,511	1,658,919	1,678,948	1,702,334	1,866,040	1,706,162	8,660,450
5	BURNED :													
6	UNITS (MMBTU)	55,602	368,490	2,594	76,504	157,130	538,028	976,667	1,148,119	1,157,605	570,851	420,485	382,071	5,854,146
7	UNIT COST (\$/MMBTU)	2.79	2.80	2.80	2.79	3	3.16	3.12	2.95	2.79	2.66	2.61	2.60	2.88
8	AMOUNT (\$)	154,910	1,030,156	7,252	213,141	459,962	1,700,469	3,045,431	3,388,363	3,231,519	1,516,388	1,097,548	993,184	16,838,323
9	ENDING INVENTORY :													
10	UNITS (MMBTU)	4,230,033	3,171,096	4,291,243	5,015,342	3,244,650	2,072,093	1,444,734	941,683	439,379	531,741	835,566	1,113,289	
11	UNIT COST (\$/MMBTU)	2.78	2.80	2.81	2.88	3.02	3.16	3.12	2.95	2.79	2.66	2.61	2.60	
12	AMOUNT (\$)	11,750,391	8,866,222	12,074,491	14,424,276	9,806,273	6,549,486	4,508,566	2,779,122	1,226,551	1,412,497	2,180,989	2,893,967	
13	DAYS SUPPLY:	0	0	0	0	0	0	#DIV/0!	18	8	10	16	21	
									2,779,122	1,226,551	1,412,497	2,180,989	2,893,967	
									0	0	0	0	0	
GAS (Reported on a MMBTU and \$ basis)														
13	BURNED :													
14	UNITS (MMBTU)	5,621,881	5,736,867	4,052,271	1,904,393	3,726,448	4,746,236	5,871,639	6,713,115	6,233,575	4,725,784	4,499,403	3,082,404	56,914,016
15	UNIT COST (\$/MMBTU)	2.86	4.06	3.17	3.19	3.71	3.82	4.42	4.10	4.34	4.51	4.29	4.42	3.95
16	AMOUNT (\$)	16,078,377	23,272,618	12,842,649	6,079,501	13,842,112	18,113,284	25,965,499	27,535,673	27,041,454	21,296,453	19,297,123	13,616,173	224,980,916
OTHER - C.T. OIL														
17	PURCHASES :													
18	UNITS (BBL)	49	(90)	(12)	(8)	(15)	5,816	20,121	45,000	35,000	25,053	0	0	130,914
19	UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	95.19	96.39	98.00	95.33	95.35	0.00	0.00	96.46
20	AMOUNT (\$)	0	0	0	0	0	553,617	1,939,470	4,409,841	3,336,401	2,388,838	0	0	12,628,167
21	BURNED :													
22	UNITS (BBL)	0	45	0	214	0	75	0	0	0	0	0	0	334
23	UNIT COST (\$/BBL)	0.00	88.07	0.00	88.29	0.00	88.55	0.00	0.00	0.00	0.00	0.00	0.00	88.32
24	AMOUNT (\$)	0	3,963	0	18,895	0	6,641	0	0	0	0	0	0	29,499
25	ENDING INVENTORY :													
26	UNITS (BBL)	7,636	7,501	7,489	7,267	7,252	12,993	33,114	78,114	113,114	138,167	138,167	138,167	
27	UNIT COST (\$/BBL)	87.02	88.06	88.20	88.29	88.47	91.48	94.46	96.50	96.14	95.99	95.99	95.99	
28	AMOUNT (\$)	664,469	660,507	660,507	641,612	641,612	1,188,587	3,128,057	7,537,898	10,874,299	13,263,137	13,263,137	13,263,137	
29	HOURS SUPPLY:	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	

(1) Includes Gulf's 100% ownership in Scherer Unit 3.

Schedule E-9**ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2021 - JULY 2021 / ESTIMATED FOR AUGUST 2021 - DECEMBER 2021**

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Month	Type & Schedule	Total KWH Purchased	Transaction Cost ¢ / kWh	Total \$ for Fuel Adj.
	JANUARY				
1		Southern Co. Interchange	10,122,839	1.90	191,987
2		Economy Purchases	5,160,768	3.45	177,977
3		Other Purchases	512,400,342	2.99	15,308,319
4		TOTAL ACTUAL PURCHASES	527,683,949	2.97	15,678,283
	FEBRUARY				
5		Southern Co. Interchange	10,368,966	4.95	513,009
6		Economy Purchases	5,389,186	4.03	216,992
7		Other Purchases	372,645,481	3.74	13,930,906
8		TOTAL ACTUAL PURCHASES	388,403,633	3.77	14,660,907
	MARCH				
9		Southern Co. Interchange	6,625,213	2.29	151,444
10		Economy Purchases	3,729,064	2.97	110,695
11		Other Purchases	521,558,477	3.28	17,118,464
12		TOTAL ACTUAL PURCHASES	531,912,754	3.27	17,380,603
	APRIL				
13		Southern Co. Interchange	194,461,329	2.79	5,432,171
14		Economy Purchases	4,878,544	2.95	143,828
15		Other Purchases	193,005,931	4.10	7,919,942
16		TOTAL ACTUAL PURCHASES	392,345,804	3.44	13,495,941
	MAY				
17		Southern Co. Interchange	158,649,997	2.84	4,511,820
18		Economy Purchases	6,217,584	3.06	190,259
19		Other Purchases	266,769,813	3.86	10,286,337
20		TOTAL ACTUAL PURCHASES	431,637,394	3.47	14,988,416
	JUNE				
21		Southern Co. Interchange	27,925,797	3.05	851,969
22		Economy Purchases	1,968,634	3.45	67,872
23		Other Purchases	492,497,233	3.57	17,604,081
24		TOTAL ACTUAL PURCHASES	522,391,664	3.55	18,523,922

Schedule E-9**ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2021 - JULY 2021 / ESTIMATED FOR AUGUST 2021 - DECEMBER 2021**

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Month	Type & Schedule	Total KWH Purchased	Transaction Cost ¢ / kWh	Total \$ for Fuel Adj.
	JULY				
1		Southern Co. Interchange	8,370,732	3.39	283,433
2		Economy Purchases	3,496,415	3.83	134,033
3		Other Purchases	533,538,538	3.69	19,667,439
4		TOTAL ACTUAL PURCHASES	545,405,685	3.68	20,084,905
	AUGUST				
5		Southern Co. Interchange	3,495,000	4.09	142,968
6		Economy Purchases	1,700,000	3.42	58,133
7		Other Purchases	622,432,000	3.46	21,506,000
8		TOTAL ESTIMATED PURCHASES	627,627,000	3.46	21,707,101
	SEPTEMBER				
9		Southern Co. Interchange	13,333,000	2.82	375,789
10		Economy Purchases	2,704,000	3.35	90,568
11		Other Purchases	612,677,000	3.59	21,995,000
12		TOTAL ESTIMATED PURCHASES	628,714,000	3.57	22,461,357
	OCTOBER				
13		Southern Co. Interchange	86,197,000	2.96	2,547,644
14		Economy Purchases	2,435,000	3.30	80,399
15		Other Purchases	247,686,000	4.39	10,864,000
16		TOTAL ESTIMATED PURCHASES	336,318,000	4.01	13,492,043
	NOVEMBER				
17		Southern Co. Interchange	12,795,000	2.57	328,362
18		Economy Purchases	1,141,000	2.97	33,883
19		Other Purchases	323,651,000	4.06	13,133,000
20		TOTAL ESTIMATED PURCHASES	337,587,000	4.00	13,495,244
	DECEMBER				
21		Southern Co. Interchange	9,844,000	2.65	260,417
22		Economy Purchases	1,102,000	3.19	35,206
23		Other Purchases	428,837,000	3.81	16,322,000
24		TOTAL ESTIMATED PURCHASES	439,783,000	3.78	16,617,623
	TOTAL FOR PERIOD				
25		Southern Co. Interchange	542,188,873	2.88	15,591,013
26		Economy Purchases	39,922,195	3.36	1,339,845
27		Other Purchases	5,127,698,815	3.62	185,655,488
28		TOTAL ACT/EST PURCHASES	5,709,809,883	3.55	202,586,345

Totals may not add due to rounding

**APPENDIX IV
CAPACITY COST RECOVERY**

JANUARY 2022 THROUGH DECEMBER 2022 FACTORS

**RBD-7
DOCKET NO. 20210001-EI
FPL WITNESS: RENAE B. DEATON
EXHIBIT _____
PAGES 1-30
SEPTEMBER 3, 2021**

**APPENDIX IV
CAPACITY COST RECOVERY
2022 FACTORS - JAN 2022 THROUGH DEC 2022
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
PROJECTED CAPACITY COSTS

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1	Base													
2	Payments to Non-cogenerators	\$1,364,000	\$1,364,000	\$1,364,000	\$1,364,000	\$1,364,000	\$1,410,800	\$1,410,800	\$1,410,800	\$1,410,800	\$1,410,800	\$1,410,800	\$1,410,800	\$16,695,600
3	Payments to Co-generators	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$1,507,380
4	Transmission of Electricity by Others	\$87,581	\$44,452	\$30,128	\$24,952	\$6,656	\$2,496	\$14,742	\$1,447	\$16,438	\$19,355	\$29,027	\$17,547	\$294,821
5	Transmission Revenues from Capacity Sales	(\$818,123)	(\$900,170)	(\$533,287)	(\$478,407)	(\$386,015)	(\$282,132)	(\$207,047)	(\$262,404)	(\$239,384)	(\$273,201)	(\$525,000)	(\$612,317)	(\$5,517,487)
6	Incremental Plant Security Costs O&M	\$2,310,584	\$2,078,461	\$2,420,830	\$2,203,658	\$2,136,912	\$2,240,836	\$2,237,160	\$2,190,077	\$2,169,409	\$2,423,182	\$2,142,190	\$2,676,595	\$27,229,893
7	Incremental Plant Security Costs Capital	\$391,497	\$389,050	\$389,865	\$392,476	\$395,847	\$399,404	\$403,679	\$408,662	\$414,170	\$419,748	\$423,905	\$434,770	\$4,863,074
8	Incremental Nuclear NRC Compliance Costs O&M	\$64,111	\$63,544	\$65,350	\$64,240	\$64,854	\$64,814	\$64,259	\$65,413	\$64,843	\$64,214	\$64,715	\$64,656	\$775,013
9	Incremental Nuclear NRC Compliance Costs Capital	\$1,035,893	\$1,029,088	\$1,025,442	\$1,019,259	\$1,011,830	\$1,007,667	\$1,004,862	\$1,002,217	\$998,206	\$994,235	\$988,024	\$981,824	\$12,098,547
10	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	\$8,688,948	\$8,657,312	\$8,625,675	\$8,594,038	\$8,562,402	\$8,530,765	\$8,499,128	\$8,467,492	\$8,435,855	\$8,404,218	\$8,372,582	\$8,340,945	\$102,179,359
11	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	(\$75,578)	(\$75,164)	(\$74,749)	(\$74,335)	(\$73,921)	(\$73,506)	(\$73,092)	(\$72,677)	(\$72,263)	(\$71,849)	(\$71,434)	(\$71,020)	(\$879,588)
12	Indiantown Transaction - Regulatory Asset - Amortization and Return	\$5,532,365	\$5,503,906	\$5,475,446	\$5,446,987	\$5,418,528	\$5,390,069	\$5,361,610	\$5,333,151	\$5,304,692	\$5,276,232	\$5,247,773	\$5,219,314	\$64,510,074
13	COVID-19 Regulatory Asset Revenue Requirements	\$385,970	\$404,722	\$403,619	\$402,516	\$401,413	\$400,309	\$399,206	\$398,103	\$397,000	\$395,897	\$394,794	\$393,691	\$4,777,241
14	Subtotal Base	\$19,092,863	\$18,684,814	\$19,317,935	\$19,084,999	\$19,028,122	\$19,217,138	\$19,240,922	\$19,067,896	\$19,025,380	\$19,188,446	\$18,602,990	\$18,982,420	\$228,533,925
15														
16	General													
17	Incremental Plant Security Costs Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
18	Subtotal General	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
19														
20	Intermediate													
21	Payments to Non-cogenerators	\$6,265,800	\$6,265,800	\$6,265,800	\$6,265,800	\$6,265,800	\$6,265,800	\$6,265,800	\$6,265,800	\$6,265,800	\$6,265,800	\$6,265,800	\$6,265,800	\$75,189,600
22	Incremental Plant Security Costs Capital	\$68,054	\$67,909	\$67,765	\$67,620	\$67,476	\$67,331	\$67,186	\$67,042	\$66,897	\$66,753	\$66,608	\$66,463	\$807,104
23	Subtotal Intermediate	\$6,333,854	\$6,333,709	\$6,333,565	\$6,333,420	\$6,333,276	\$6,333,131	\$6,332,986	\$6,332,842	\$6,332,697	\$6,332,553	\$6,332,408	\$6,332,263	\$75,996,704
24														
25	Peaking													
26	Payments to Non-cogenerators	(\$3,333)	(\$3,333)	(\$3,333)	(\$3,333)	(\$3,333)	(\$3,333)	-	-	-	-	-	-	(\$20,000)
27	Incremental Plant Security Costs Capital	\$6,477	\$6,456	\$6,435	\$6,413	\$6,392	\$6,371	\$6,350	\$6,328	\$6,307	\$6,286	\$6,265	\$6,244	\$76,323
28	Subtotal Peaking	\$3,144	\$3,122	\$3,101	\$3,080	\$3,059	\$3,038	\$6,350	\$6,328	\$6,307	\$6,286	\$6,265	\$6,244	\$56,323
29														
30	Solar													
31	Incremental Plant Security Costs Capital	\$5,775	\$5,748	\$5,721	\$5,695	\$5,668	\$5,641	\$5,614	\$5,588	\$5,561	\$5,534	\$5,508	\$5,481	\$67,534
32	Subtotal Solar	\$5,775	\$5,748	\$5,721	\$5,695	\$5,668	\$5,641	\$5,614	\$5,588	\$5,561	\$5,534	\$5,508	\$5,481	\$67,534
33														
34	Total	\$25,435,636	\$25,027,394	\$25,660,322	\$25,427,194	\$25,370,124	\$25,558,947	\$25,585,873	\$25,412,654	\$25,369,946	\$25,532,819	\$24,947,170	\$25,326,408	\$304,654,486
35														
36	Totals may not add due to rounding													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
JURISDICTIONALIZED CAPACITY COSTS

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1														
2	Total Capacity Costs	\$25,435,636	\$25,027,394	\$25,660,322	\$25,427,194	\$25,370,124	\$25,558,947	\$25,585,873	\$25,412,654	\$25,369,946	\$25,532,819	\$24,947,170	\$25,326,408	\$304,654,486
3														
4	Total Base Capacity Costs	\$19,092,863	\$18,684,814	\$19,317,935	\$19,084,999	\$19,028,122	\$19,217,138	\$19,240,922	\$19,067,896	\$19,025,380	\$19,188,446	\$18,602,990	\$18,982,420	\$228,533,925
5	Base Jurisdictional Factor	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%
6	Total Base Jurisdictionalized Capacity Costs	\$18,316,051	\$17,924,604	\$18,531,965	\$18,308,507	\$18,253,943	\$18,435,269	\$18,458,086	\$18,292,100	\$18,251,314	\$18,407,745	\$17,846,109	\$18,210,101	\$219,235,794
7														
8	Total General Capacity Costs	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
9	General Jurisdictional Factor	96.9001%	96.9001%	96.9001%	96.9001%	96.9001%	96.9001%	96.9001%	96.9001%	96.9001%	96.9001%	96.9001%	96.9001%	96.9001%
10	Total General Jurisdictionalized Capacity Costs	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11														
12	Total Intermediate Capacity Costs	\$6,333,854	\$6,333,709	\$6,333,565	\$6,333,420	\$6,333,276	\$6,333,131	\$6,332,986	\$6,332,842	\$6,332,697	\$6,332,553	\$6,332,408	\$6,332,263	\$75,996,704
13	Intermediate Jurisdictional Factor	95.4287%	95.4287%	95.4287%	95.4287%	95.4287%	95.4287%	95.4287%	95.4287%	95.4287%	95.4287%	95.4287%	95.4287%	95.4287%
14	Total Intermediate Jurisdictionalized Capacity Costs	\$6,044,314	\$6,044,176	\$6,044,038	\$6,043,901	\$6,043,763	\$6,043,625	\$6,043,487	\$6,043,349	\$6,043,211	\$6,043,073	\$6,042,935	\$6,042,797	\$72,522,666
15														
16	Total Peaking Capacity Costs	\$3,144	\$3,122	\$3,101	\$3,080	\$3,059	\$3,038	\$6,350	\$6,328	\$6,307	\$6,286	\$6,265	\$6,244	\$56,323
17	Peaking Jurisdictional Factor	95.1837%	95.1837%	95.1837%	95.1837%	95.1837%	95.1837%	95.1837%	95.1837%	95.1837%	95.1837%	95.1837%	95.1837%	95.1837%
18	Total Peaking Jurisdictionalized Capacity Costs	\$2,992	\$2,972	\$2,952	\$2,932	\$2,911	\$2,891	\$6,044	\$6,024	\$6,003	\$5,983	\$5,963	\$5,943	\$53,611
19														
20	Total Solar Capacity Costs	\$5,775	\$5,748	\$5,721	\$5,695	\$5,668	\$5,641	\$5,614	\$5,588	\$5,561	\$5,534	\$5,508	\$5,481	\$67,534
21	Solar Jurisdictional Factor	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%	95.9314%
22	Total Solar Jurisdictionalized Capacity Costs	\$5,540	\$5,514	\$5,489	\$5,463	\$5,437	\$5,412	\$5,386	\$5,360	\$5,335	\$5,309	\$5,284	\$5,258	\$64,786
23														
24	Total Transmission Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Transmission Jurisdictional Factor	90.2581%	90.2581%	90.2581%	90.2581%	90.2581%	90.2581%	90.2581%	90.2581%	90.2581%	90.2581%	90.2581%	90.2581%	90.2581%
26	Total Transmission Jurisdictionalized Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
27														
28	Jurisdictionalized Capacity Costs	\$24,368,897	\$23,977,266	\$24,584,444	\$24,360,802	\$24,306,055	\$24,487,197	\$24,513,002	\$24,346,832	\$24,305,862	\$24,462,110	\$23,900,290	\$24,264,099	\$291,876,857
29														
30														
31	FINAL TRUE-UP -- (Over)/Under Recovery													(\$4,701,739)
32	ACT/EST TRUE-UP -- (Over)/Under Recovery													(\$6,604,690)
33	GBRA True-up													(\$5,055,917)
34	SoBRA True-up													(\$204,750)
35	Total (Lines 28 + 31 + 32 + 33 + 34)													\$275,309,761
36	Revenue Tax Multiplier													1.00000
37	Total Recoverable Capacity Costs													\$275,309,761
38														
39	Totals may not add due to rounding													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
CALCULATION OF ENERGY RATE DEMAND ALLOCATION % BY RATE CLASS
ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Rate Class Summary - Non-Fuel	Avg 12 CP Load Factor at Meter (%) ⁽¹⁾	Projected Sales at Meter (kWh) ⁽²⁾	Projected Avg 12 CP at Meter (kW) ⁽³⁾	Demand Loss Expansion Factor ⁽⁴⁾	Energy Loss Expansion Factor ⁽⁵⁾	Projected Sales at Generation (kWh) ⁽⁶⁾	Projected Avg 12 CP at Generation (kW) ⁽⁷⁾	Percentage of Sales at Generation (%) ⁽⁸⁾	Percentage of Demand at Generation (%) ⁽⁹⁾
1	RS1/RTR1	62.22%	65,315,938,669	11,983,542	1.064490	1.049080	68,521,615,430	12,756,366	53.56161%	56.89321%
2	GS1/GST1	59.71%	8,368,517,064	1,599,867	1.064490	1.049080	8,779,240,101	1,703,043	6.86251%	7.59555%
3	GSD1/GSDT1/HLFT1/GSD1-EV	70.61%	28,295,907,165	4,574,458	1.064390	1.049001	29,682,420,829	4,869,006	23.20200%	21.71570%
4	OS2	105.81%	9,900,936	1,068	1.035531	1.027440	10,172,620	1,106	0.00795%	0.00493%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	69.94%	10,335,974,594	1,687,046	1.062797	1.047837	10,830,414,999	1,792,986	8.46586%	7.99669%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	81.33%	3,825,387,076	536,952	1.052019	1.039747	3,977,433,808	564,884	3.10906%	2.51937%
7	GSLD3/GSLDT3/CS3/CST3	84.01%	960,788,986	130,551	1.020849	1.016408	976,553,509	133,273	0.76335%	0.59440%
8	SST1T	62.77%	65,710,604	11,950	1.020849	1.016408	66,788,776	12,199	0.05221%	0.05441%
9	SST1D1/SST1D2/SST1D3	148.28%	1,410,876	109	1.035531	1.027440	1,449,591	112	0.00113%	0.00050%
10	CILC D/CILC G	85.41%	2,647,478,080	353,859	1.052744	1.040421	2,754,493,069	372,522	2.15312%	1.66144%
11	CILC T	92.91%	1,504,497,392	184,861	1.020849	1.016408	1,529,183,023	188,715	1.19532%	0.84167%
12	MET	75.08%	84,974,524	12,921	1.035531	1.027440	87,306,241	13,380	0.06825%	0.05967%
13	OL1/SL1/SL1M/PL1/OSI/II	56,888.75%	569,918,549	114	1.064490	1.049080	597,889,893	122	0.46736%	0.00054%
14	SL2/SL2M/GSCU1	96.38%	110,096,899	13,041	1.064490	1.049080	115,500,405	13,882	0.09028%	0.06191%
15	Total		122,096,501,415	21,090,338			127,930,462,295	22,421,597	100.00000%	100.00000%

⁽¹⁾ Calculated: Col(4)/8760 hours / Col(5)

⁽²⁾ Projected kwh sales for the period January 2022 through December 2022.

⁽³⁾ AVG 12 CP load factor based on 2018-2020 load research data and 2022 projections.

⁽⁴⁾ Based on 2022 demand losses.

⁽⁵⁾ Based on 2022 energy losses.

⁽⁶⁾ Col(4) * Col(7)

⁽⁷⁾ Col(5) * Col(6)

⁽⁸⁾ Col(8) / Total for Col(8)

⁽⁹⁾ Col(9) / Total for Col(9)

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Rate Schedule	Percentage of Sales at Generation (%) ⁽¹⁾	Percentage of Demand at Generation (%) ⁽²⁾	Energy Related Cost (\$) ⁽³⁾	Demand Related Cost (\$) ⁽⁴⁾	Total Capacity Costs (\$) ⁽⁵⁾	Projected Sales at Meter (kwh) ⁽⁶⁾	Billing KW Load Factor (%) ⁽⁷⁾	Projected Billed KW at Meter (KW) ⁽⁸⁾	Capacity Recovery Factor (\$/KW) ⁽⁹⁾	Capacity Recovery Factor (\$/kwh) ⁽¹⁰⁾	RDC (\$/KW) ⁽¹¹⁾	SDD (\$/KW) ⁽¹²⁾
1	RS1/RTR1	53.561610%	56.893209%	11,343,103	144,583,900	155,927,003	65,315,938,669				0.00239		
2	GS1/GST1	6.862509%	7.595547%	1,453,320	19,302,723	20,756,043	8,368,517,064				0.00248		
3	GSD1/GSDT1/HLFT1/GSD1-EV	23.201996%	21.715697%	4,913,643	55,186,553	60,100,196	28,295,907,165	52.650226%	73,620,799	0.81635			
4	OS2	0.007952%	0.004933%	1,684	12,537	14,221	9,900,936				0.00144		
5	GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	8.465861%	7.996694%	1,792,872	20,322,165	22,115,037	10,335,974,594	57.653091%	24,558,734	0.90050			
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	3.109059%	2.519374%	658,426	6,402,538	7,060,965	3,825,387,076	66.857211%	7,837,982	0.90087			
7	GSLD3/GSLDT3/CS3/CST3	0.763347%	0.594396%	161,659	1,510,550	1,672,209	960,788,986	64.416587%	2,043,184	0.81843			
8	SST1T	0.052207%	0.054408%	11,056	138,267	149,323	65,710,604	12.160339%	740,230			0.10	0.05
9	SST1D1/SST1D2/SST1D3	0.001133%	0.000502%	240	1,275	1,515	1,410,876	3.546427%	54,497			0.11	0.05
10	CILC D/CILC G	2.153117%	1.661445%	455,980	4,222,265	4,678,245	2,647,478,080	71.022441%	5,106,389	0.91616			
11	CILC T	1.195324%	0.841667%	253,142	2,138,946	2,392,088	1,504,497,392	76.599518%	2,690,559	0.88907			
12	MET	0.068245%	0.059673%	14,453	151,648	166,101	84,974,524	54.257163%	214,540	0.77422			
13	OL1/SL1/SL1M/PL1/OS1/II	0.467355%	0.000543%	98,975	1,380	100,355	569,918,549				0.00018		
14	SL2/SL2M/GSCU1	0.090284%	0.061913%	19,120	157,340	176,460	110,096,899				0.00160		
15	Total			21,177,674	254,132,087	275,309,761	122,096,501,415						
16													
17	⁽¹⁾ Obtained from Page 3, Col(10)												
18	⁽²⁾ Obtained from Page 3, Col(11)												
19	⁽³⁾ (Total Capacity Costs/13) * Col(3)												
20	⁽⁴⁾ (Total Capacity Costs/13 * 12) * Col(4)												
21	⁽⁵⁾ Col(5) + Col(6)												
22	⁽⁶⁾ Projected kwh sales for the period January 2022 through December 2022.												
23	⁽⁷⁾ (kWh sales / 8760 hours)/(avg customer NCP)												
24	⁽⁸⁾ Col(8) / (Col(9) * 730)												
25	⁽⁹⁾ Col(7) / Col(10)												
26	⁽¹⁰⁾ Col(7) / Col(8)												
27	⁽¹¹⁾ RDC = Reservation Demand Charge - (Total Col 7)/(total of avg 12 CP at generation)/(10)(rate demand loss expansion factor)/12 Months												
28	⁽¹²⁾ SDD = Sum of Daily Demand Charge - (Total Col 7)/(total of avg 12 CP at generation)/(21 on peak days)(rate demand loss expansion factor)/12 Months												
29													
30	Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.												
31													
32	Totals may not add due to rounding												

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
Return on Capital Investments, Depreciation and Taxes

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

Line	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
202-INCREMENTAL SECURITY														
Base														
1. Investments														
a. Expenditures/Additions		\$43,736	\$92,526	\$398,148	\$619,763	\$621,850	\$674,035	\$778,405	\$882,775	\$987,145	\$903,274	\$569,665	\$428,678	\$7,000,000
b. Additions to Plants		-	-	-	-	-	-	\$198,240	-	-	-	-	\$8,357,673	\$8,555,913
c. Retirements		(\$344,458)	-	-	-	-	-	-	-	-	-	-	-	(\$344,458)
d. Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$40,335,325	\$39,990,867	\$39,990,867	\$39,990,867	\$39,990,867	\$39,990,867	\$39,990,867	\$40,189,107	\$40,189,107	\$40,189,107	\$40,189,107	\$40,189,107	\$48,546,780	
3. Less: Accumulated Depreciation	\$2,830,709	\$2,613,803	\$2,739,304	\$2,864,806	\$2,990,307	\$3,115,808	\$3,241,310	\$3,366,997	\$3,492,870	\$3,618,743	\$3,744,616	\$3,870,489	\$4,004,716	
4. CWIP - Non Interest Bearing	\$1,310,053	\$1,353,789	\$1,446,315	\$1,844,462	\$2,464,225	\$3,086,075	\$3,760,110	\$4,340,275	\$5,223,050	\$6,210,195	\$7,113,469	\$7,683,134	(\$245,860)	
5. Net Investment (Lines 2 - 3 + 4)	\$38,814,669	\$38,730,853	\$38,697,878	\$38,970,524	\$39,464,785	\$39,961,134	\$40,509,667	\$41,162,385	\$41,919,287	\$42,780,559	\$43,557,960	\$44,001,752	\$44,296,204	
6. Average Net Investment		\$38,772,761	\$38,714,366	\$38,834,201	\$39,217,655	\$39,712,960	\$40,235,401	\$40,836,026	\$41,540,836	\$42,349,923	\$43,169,260	\$43,779,856	\$44,148,978	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ⁽¹⁾		\$225,630	\$225,291	\$225,988	\$228,219	\$231,102	\$234,142	\$237,637	\$241,739	\$246,447	\$251,215	\$254,768	\$256,916	\$2,859,094
b. Debt Component (Line 6 x debt rate) ⁽²⁾		\$38,315	\$38,258	\$38,376	\$38,755	\$39,244	\$39,761	\$40,354	\$41,051	\$41,850	\$42,660	\$43,263	\$43,628	\$485,515
8. Investment Expenses														
a. Depreciation		\$127,552	\$125,501	\$125,501	\$125,501	\$125,501	\$125,501	\$125,687	\$125,873	\$125,873	\$125,873	\$125,873	\$134,226	\$1,518,465
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$391,497	\$389,050	\$389,865	\$392,476	\$395,847	\$399,404	\$403,679	\$408,662	\$414,170	\$419,748	\$423,905	\$434,770	\$4,863,074

⁽¹⁾ The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

⁽²⁾ The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
Return on Capital Investments, Depreciation and Taxes

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

Line	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
202-INCREMENTAL SECURITY														
Intermediate														
1. Investments														
a. Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
b. Additions to Plants		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553	\$7,792,553
3. Less: Accumulated Depreciation	\$941,928	\$963,169	\$984,411	\$1,005,652	\$1,026,893	\$1,048,134	\$1,069,376	\$1,090,617	\$1,111,858	\$1,133,099	\$1,154,340	\$1,175,582	\$1,196,823	\$1,196,823
4. CWIP - Non Interest Bearing	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634	\$36,634
5. Net Investment (Lines 2 - 3 + 4)	\$6,887,258	\$6,866,017	\$6,844,776	\$6,823,535	\$6,802,294	\$6,781,052	\$6,759,811	\$6,738,570	\$6,717,329	\$6,696,087	\$6,674,846	\$6,653,605	\$6,632,364	\$6,632,364
6. Average Net Investment		\$6,876,638	\$6,855,397	\$6,834,155	\$6,812,914	\$6,791,673	\$6,770,432	\$6,749,191	\$6,727,949	\$6,706,708	\$6,685,467	\$6,664,226	\$6,642,984	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ⁽¹⁾		\$40,017	\$39,894	\$39,770	\$39,646	\$39,523	\$39,399	\$39,276	\$39,152	\$39,028	\$38,905	\$38,781	\$38,658	\$472,049
b. Debt Component (Line 6 x debt rate) ⁽²⁾		\$6,795	\$6,775	\$6,754	\$6,733	\$6,712	\$6,691	\$6,670	\$6,649	\$6,628	\$6,607	\$6,586	\$6,565	\$80,161
8. Investment Expenses														
a. Depreciation		\$21,241	\$21,241	\$21,241	\$21,241	\$21,241	\$21,241	\$21,241	\$21,241	\$21,241	\$21,241	\$21,241	\$21,241	\$254,895
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$68,054	\$67,909	\$67,765	\$67,620	\$67,476	\$67,331	\$67,186	\$67,042	\$66,897	\$66,753	\$66,608	\$66,463	\$807,104

⁽¹⁾ The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

⁽²⁾ The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
Return on Capital Investments, Depreciation and Taxes

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

Line	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
202-INCREMENTAL SECURITY														
Peaking														
1. Investments														
a. Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
b. Additions to Plants		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269	\$750,269
3. Less: Accumulated Depreciation	\$218,280	\$221,396	\$224,512	\$227,627	\$230,743	\$233,859	\$236,975	\$240,091	\$243,207	\$246,322	\$249,438	\$252,554	\$255,670	\$255,670
4. CWIP - Non Interest Bearing	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)	(\$36,696)
5. Net Investment (Lines 2 - 3 + 4)	\$495,293	\$492,177	\$489,061	\$485,945	\$482,830	\$479,714	\$476,598	\$473,482	\$470,366	\$467,250	\$464,134	\$461,019	\$457,903	
6. Average Net Investment		\$493,735	\$490,619	\$487,503	\$484,387	\$481,272	\$478,156	\$475,040	\$471,924	\$468,808	\$465,692	\$462,577	\$459,461	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ⁽¹⁾		\$2,873	\$2,855	\$2,837	\$2,819	\$2,801	\$2,783	\$2,764	\$2,746	\$2,728	\$2,710	\$2,692	\$2,674	\$33,282
b. Debt Component (Line 6 x debt rate) ⁽²⁾		\$488	\$485	\$482	\$479	\$476	\$473	\$469	\$466	\$463	\$460	\$457	\$454	\$5,652
8. Investment Expenses														
a. Depreciation		\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$3,116	\$37,390
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$6,477	\$6,456	\$6,435	\$6,413	\$6,392	\$6,371	\$6,350	\$6,328	\$6,307	\$6,286	\$6,265	\$6,244	\$76,323

⁽¹⁾ The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

⁽²⁾ The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
Return on Capital Investments, Depreciation and Taxes

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

Line	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
203-INCREMENTAL SECURITY - SOLAR														
Solar														
1. Investments														
a. Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
b. Additions to Plants		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	\$329,524	
3. Less: Accumulated Depreciation	\$55,550	\$59,473	\$63,396	\$67,319	\$71,242	\$75,165	\$79,088	\$83,011	\$86,934	\$90,857	\$94,779	\$98,702	\$102,625	
4. CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5. Net Investment (Lines 2 - 3 + 4)	\$273,974	\$270,051	\$266,128	\$262,205	\$258,283	\$254,360	\$250,437	\$246,514	\$242,591	\$238,668	\$234,745	\$230,822	\$226,899	
6. Average Net Investment		\$272,013	\$268,090	\$264,167	\$260,244	\$256,321	\$252,398	\$248,475	\$244,552	\$240,629	\$236,706	\$232,783	\$228,860	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ⁽¹⁾		\$1,583	\$1,560	\$1,537	\$1,514	\$1,492	\$1,469	\$1,446	\$1,423	\$1,400	\$1,377	\$1,355	\$1,332	\$17,488
b. Debt Component (Line 6 x debt rate) ⁽²⁾		\$269	\$265	\$261	\$257	\$253	\$249	\$246	\$242	\$238	\$234	\$230	\$226	\$2,970
8. Investment Expenses														
a. Depreciation		\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$3,923	\$47,076
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$5,775	\$5,748	\$5,721	\$5,695	\$5,668	\$5,641	\$5,614	\$5,588	\$5,561	\$5,534	\$5,508	\$5,481	\$67,534

⁽¹⁾ The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

⁽²⁾ The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
Return on Capital Investments, Depreciation and Taxes

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

Line	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
201-FUKUSHIMA														
Base														
1. Investments														
a. Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
b. Additions to Plants		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Retirements		(\$540,749)	(\$148,590)	(\$12,785)	(\$577,410)	(\$226,968)	(\$32,209)	-	(\$5,293)	(\$230,386)	(\$117)	(\$609,561)	(\$2,425)	(\$2,386,494)
d. Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-
e. Salvage		-	-	-	-	-	-	-	-	-	-	-	-	-
f. Transfer Adjustments/Other		-	-	-	-	-	-	-	-	-	-	-	-	-
2. Plant-In-Service/Depreciation Base	\$110,804,982	\$110,264,233	\$110,115,642	\$110,102,857	\$109,525,447	\$109,298,479	\$109,266,270	\$109,266,270	\$109,260,977	\$109,030,591	\$109,030,474	\$108,420,913	\$108,418,488	
3. Less: Accumulated Depreciation	\$18,932,178	\$18,790,419	\$19,036,717	\$19,417,859	\$19,230,864	\$19,389,522	\$19,741,397	\$20,125,289	\$20,503,856	\$20,655,928	\$21,036,896	\$20,804,792	\$21,176,180	
4. CWIP - Non Interest Bearing	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520	\$1,885,520
5. Net Investment (Lines 2 - 3 + 4)	\$93,758,324	\$93,359,333	\$92,964,445	\$92,570,517	\$92,180,103	\$91,794,477	\$91,410,393	\$91,026,501	\$90,642,641	\$90,260,183	\$89,879,098	\$89,501,641	\$89,127,828	
6. Average Net Investment		\$93,558,828	\$93,161,889	\$92,767,481	\$92,375,310	\$91,987,290	\$91,602,435	\$91,218,447	\$90,834,571	\$90,451,412	\$90,069,641	\$89,690,370	\$89,314,734	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes ⁽¹⁾		\$544,447	\$542,137	\$539,842	\$537,560	\$535,302	\$533,062	\$530,828	\$528,594	\$526,364	\$524,142	\$521,935	\$519,749	\$6,383,963
b. Debt Component (Line 6 x debt rate) ⁽²⁾		\$92,455	\$92,063	\$91,673	\$91,285	\$90,902	\$90,522	\$90,142	\$89,763	\$89,384	\$89,007	\$88,632	\$88,261	\$1,084,087
8. Investment Expenses														
a. Depreciation		\$398,991	\$394,888	\$393,927	\$390,414	\$385,626	\$384,084	\$383,892	\$383,860	\$382,458	\$381,086	\$377,456	\$373,814	\$4,630,496
b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
c. Dismantlements		-	-	-	-	-	-	-	-	-	-	-	-	-
d. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
9. Total System Recoverable Expenses (Lines 7 & 8)		\$1,035,893	\$1,029,088	\$1,025,442	\$1,019,259	\$1,011,830	\$1,007,667	\$1,004,862	\$1,002,217	\$998,206	\$994,235	\$988,024	\$981,824	\$12,098,547

⁽¹⁾ The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

⁽²⁾ The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
Cedar Bay Transaction - Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

Line No.	Line	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1	Regulatory Asset Loss of PPA ⁽¹⁾		\$167,303,589	\$162,656,267	\$158,008,945	\$153,361,623	\$148,714,301	\$144,066,979	\$139,419,657	\$134,772,335	\$130,125,013	\$125,477,691	\$120,830,369	\$116,183,047	
2															
3	Regulatory Asset - Loss of PPA Amort		\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$4,647,322	\$55,767,864
4															
5	Unamortized Regulatory Asset - Loss of PPA	\$167,303,589	\$162,656,267	\$158,008,945	\$153,361,623	\$148,714,301	\$144,066,979	\$139,419,657	\$134,772,335	\$130,125,013	\$125,477,691	\$120,830,369	\$116,183,047	\$111,535,725	
6															
7	Average Unamortized Regulatory Asset - Loss of PPA		\$164,979,928	\$160,332,606	\$155,685,284	\$151,037,962	\$146,390,640	\$141,743,318	\$137,095,996	\$132,448,674	\$127,801,352	\$123,154,030	\$118,506,708	\$113,859,386	
8															
9	Regulatory Asset - Income Tax Gross Up ⁽¹⁾		\$105,066,901	\$102,148,376	\$99,229,851	\$96,311,326	\$93,392,801	\$90,474,276	\$87,555,751	\$84,637,226	\$81,718,701	\$78,800,176	\$75,881,651	\$72,963,126	
10															
11	Regulatory Asset Amortization - Income Tax Gross-Up		\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$2,918,525	\$35,022,300
12															
13	Unamortized Regulatory Asset - Income Tax Gross Up	\$105,066,901	\$102,148,376	\$99,229,851	\$96,311,326	\$93,392,801	\$90,474,276	\$87,555,751	\$84,637,226	\$81,718,701	\$78,800,176	\$75,881,651	\$72,963,126	\$70,044,601	
14															
15	Return on Unamortized Regulatory Asset - Loss of PPA only														
16	Equity Component		\$716,739	\$696,549	\$676,359	\$656,169	\$635,979	\$615,790	\$595,600	\$575,410	\$555,220	\$535,030	\$514,841	\$494,651	\$7,268,337
17															
18	Equity Comp. grossed up for taxes ⁽²⁾		\$960,068	\$933,024	\$905,980	\$878,936	\$851,891	\$824,847	\$797,803	\$770,759	\$743,715	\$716,671	\$689,626	\$662,582	\$9,735,901
19															
20	Debt Component ⁽³⁾		\$163,033	\$158,441	\$153,848	\$149,256	\$144,663	\$140,071	\$135,478	\$130,886	\$126,293	\$121,701	\$117,108	\$112,516	\$1,653,294
21															
22	Total Return Requirements (Line 18 + 20)		\$1,123,101	\$1,091,465	\$1,059,828	\$1,028,191	\$996,555	\$964,918	\$933,281	\$901,645	\$870,008	\$838,371	\$806,735	\$775,098	\$11,389,195
23	Total Recoverable Costs (Line 3 + 11 + 22)		\$8,688,948	\$8,657,312	\$8,625,675	\$8,594,038	\$8,562,402	\$8,530,765	\$8,499,128	\$8,467,492	\$8,435,855	\$8,404,218	\$8,372,582	\$8,340,945	\$102,179,359
24															
25															

⁽¹⁾ Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI, Order No. PSC-15-0401-AS-EI.

⁽²⁾ The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

⁽³⁾ The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
Cedar Bay Transaction - Regulatory Liability - Book/Tax Timing Difference Associated to Plant Asset

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

Line No.	Line	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1	Regulatory Liability - Book/Tax Timing Difference ⁽¹⁾		(\$2,191,285)	(\$2,130,417)	(\$2,069,549)	(\$2,008,681)	(\$1,947,813)	(\$1,886,945)	(\$1,826,077)	(\$1,765,209)	(\$1,704,341)	(\$1,643,473)	(\$1,582,605)	(\$1,521,737)	
2															
3	Regulatory Liability Amortization		\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$60,868	\$730,416
4															
5	Unamortized Regulatory Liability - Book/Tax Timing Diff	(\$2,191,285)	(\$2,130,417)	(\$2,069,549)	(\$2,008,681)	(\$1,947,813)	(\$1,886,945)	(\$1,826,077)	(\$1,765,209)	(\$1,704,341)	(\$1,643,473)	(\$1,582,605)	(\$1,521,737)	(\$1,460,869)	
6															
7	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		(\$2,160,851)	(\$2,099,983)	(\$2,039,115)	(\$1,978,247)	(\$1,917,379)	(\$1,856,511)	(\$1,795,643)	(\$1,734,775)	(\$1,673,907)	(\$1,613,039)	(\$1,552,171)	(\$1,491,303)	
8															
9	Return on Unamortized Regulatory Asset - Loss of PPA only														
10	Equity Component		(\$9,388)	(\$9,123)	(\$8,859)	(\$8,594)	(\$8,330)	(\$8,065)	(\$7,801)	(\$7,537)	(\$7,272)	(\$7,008)	(\$6,743)	(\$6,479)	(\$95,199)
11															
12	Equity Comp. grossed up for taxes ⁽²⁾		(\$12,575)	(\$12,220)	(\$11,866)	(\$11,512)	(\$11,158)	(\$10,804)	(\$10,449)	(\$10,095)	(\$9,741)	(\$9,387)	(\$9,033)	(\$8,678)	(\$127,518)
13															
14	Debt Component ⁽³⁾		(\$2,135)	(\$2,075)	(\$2,015)	(\$1,955)	(\$1,895)	(\$1,835)	(\$1,774)	(\$1,714)	(\$1,654)	(\$1,594)	(\$1,534)	(\$1,474)	(\$21,654)
15															
16	Total Return Requirements (Line 12 + 14)		(\$14,710)	(\$14,296)	(\$13,881)	(\$13,467)	(\$13,053)	(\$12,638)	(\$12,224)	(\$11,809)	(\$11,395)	(\$10,981)	(\$10,566)	(\$10,152)	(\$149,172)
17	Total Recoverable Costs (Line 3 + 16)		(\$75,578)	(\$75,164)	(\$74,749)	(\$74,335)	(\$73,921)	(\$73,506)	(\$73,092)	(\$72,677)	(\$72,263)	(\$71,849)	(\$71,434)	(\$71,020)	(\$879,588)

⁽¹⁾ Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI, Order No. PSC-15-0401-AS-EI.

⁽²⁾ The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

⁽³⁾ The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
Indiantown Transaction - Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

Line No.	Line	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1	Regulatory Asset Loss of PPA ⁽¹⁾		\$200,666,666	\$196,486,110	\$192,305,555	\$188,124,999	\$183,944,444	\$179,763,888	\$175,583,332	\$171,402,777	\$167,222,221	\$163,041,666	\$158,861,110	\$154,680,555	
2															
3	Regulatory Asset - Loss of PPA Amort		\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$4,180,556	\$50,166,667
4															
5	Unamortized Regulatory Asset - Loss of PPA	\$200,666,666	\$196,486,110	\$192,305,555	\$188,124,999	\$183,944,444	\$179,763,888	\$175,583,332	\$171,402,777	\$167,222,221	\$163,041,666	\$158,861,110	\$154,680,555	\$150,499,999	
6															
7	Average Unamortized Regulatory Asset - Loss of PPA		\$198,576,388	\$194,395,832	\$190,215,277	\$186,034,721	\$181,854,166	\$177,673,610	\$173,493,055	\$169,312,499	\$165,131,944	\$160,951,388	\$156,770,832	\$152,590,277	
8															
9	Return on Unamortized Regulatory Asset - Loss of PPA only														
10	Equity Component		\$862,695	\$844,533	\$826,371	\$808,209	\$790,047	\$771,885	\$753,723	\$735,561	\$717,399	\$699,237	\$681,075	\$662,913	\$9,153,651
11															
12	Equity Comp. grossed up for taxes ⁽²⁾		\$1,155,576	\$1,131,248	\$1,106,920	\$1,082,592	\$1,058,264	\$1,033,936	\$1,009,609	\$985,281	\$960,953	\$936,625	\$912,297	\$887,969	\$12,261,270
13															
14	Debt Component ⁽³⁾		\$196,233	\$192,102	\$187,971	\$183,840	\$179,708	\$175,577	\$171,446	\$167,315	\$163,183	\$159,052	\$154,921	\$150,790	\$2,082,137
15															
16	Total Return Requirements (Line 12 + 14)		\$1,351,809	\$1,323,350	\$1,294,891	\$1,266,432	\$1,237,973	\$1,209,513	\$1,181,054	\$1,152,595	\$1,124,136	\$1,095,677	\$1,067,218	\$1,038,759	\$14,343,407
17	Total Recoverable Costs (Line 3 + 16)		\$5,532,365	\$5,503,906	\$5,475,446	\$5,446,987	\$5,418,528	\$5,390,069	\$5,361,610	\$5,333,151	\$5,304,692	\$5,276,232	\$5,247,773	\$5,219,314	\$64,510,074
18															
19															

⁽¹⁾ Recovery of the Indiantown Transaction is based on the settlement agreement approved by the FPSC in Docket No. 160154-EI, Order No. PSC-16-0506-FOF-EI.

⁽²⁾ The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

⁽³⁾ The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTION FILING
COVID 19 Regulatory Asset Recoverable Expenses

ESTIMATED FOR THE PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022

Line	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
COVID-19 Regulatory Asset														
1. Regulatory Asset Balance ⁽¹⁾	-	\$13,200,000	\$12,833,333	\$12,466,667	\$12,100,000	\$11,733,333	\$11,366,667	\$11,000,000	\$10,633,333	\$10,266,667	\$9,900,000	\$9,533,333	\$9,166,667	
2. Less: Amortization		(\$366,667)	(\$366,667)	(\$366,667)	(\$366,667)	(\$366,667)	(\$366,667)	(\$366,667)	(\$366,667)	(\$366,667)	(\$366,667)	(\$366,667)	(\$366,667)	(\$4,400,000)
3. Net Regulatory Asset Balance (Lines 1+2)	-	\$12,833,333	\$12,466,667	\$12,100,000	\$11,733,333	\$11,366,667	\$11,000,000	\$10,633,333	\$10,266,667	\$9,900,000	\$9,533,333	\$9,166,667	\$8,800,000	
4. Average Net Regulatory Asset Balance		\$6,416,667	\$12,650,000	\$12,283,333	\$11,916,667	\$11,550,000	\$11,183,333	\$10,816,667	\$10,450,000	\$10,083,333	\$9,716,667	\$9,350,000	\$8,983,333	
5. Return on Average Net Regulatory Asset Balance														
a. Equity Component (Line 4 x equity rate grossed up for taxes)		-	-	-	-	-	-	-	-	-	-	-	-	-
b. Debt Component (Line 4 x debt rate) ⁽²⁾		\$19,303	\$38,055	\$36,952	\$35,849	\$34,746	\$33,643	\$32,540	\$31,437	\$30,334	\$29,231	\$28,128	\$27,025	\$377,241
6. Amortization Expense														
a. Recoverable Costs		\$366,667	\$366,667	\$366,667	\$366,667	\$366,667	\$366,667	\$366,667	\$366,667	\$366,667	\$366,667	\$366,667	\$366,667	\$4,400,000
b. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
7. Total System Recoverable Expenses (Lines 5 + 6)		\$385,970	\$404,722	\$403,619	\$402,516	\$401,413	\$400,309	\$399,206	\$398,103	\$397,000	\$395,897	\$394,794	\$393,691	\$4,777,241

⁽¹⁾ Recovery of the COVID-19 asset is based on the settlement agreement approved by the FPSC in Docket No. 20200151 (Gulf).

⁽²⁾ The embedded long-term debt component is 3.61% based on FPL's most recent financial forecast.

Totals may not add due to rounding

COST RECOVERY CLAUSES
FORECASTED 2022 CONSOLIDATED @10.60% (Proposed Settlement Rate)

CAPITAL STRUCTURE AND COST RATES (a)

	Adjusted Retail	Ratio	Midpoint Cost Rates	Weighted Cost	Pre-Tax Weighted Cost
Long term debt	\$17,415,345,338	31.374%	3.61%	1.1311%	1.13%
Short term debt	\$654,983,828	1.180%	0.94%	0.0111%	0.01%
Preferred stock	\$0	0.000%	0.00%	0.0000%	0.00%
Customer Deposits	\$455,338,901	0.820%	2.03%	0.0167%	0.02%
Common Equity ^(b)	\$26,665,503,451	48.039%	10.60%	5.0921%	6.82%
Deferred Income Tax	\$9,267,598,436	16.696%	0.00%	0.0000%	0.00%
Investment Tax Credits					
Zero cost	\$0	0.000%	0.00%	0.0000%	0.00%
Weighted cost	\$1,049,225,596	1.890%	7.84%	0.1481%	0.19%
TOTAL	\$55,507,995,549	100.00%		6.3991%	8.17%

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

	Adjusted Retail	Ratio	Cost Rate	Weighted Cost	Pre-Tax Cost
Long term debt	\$17,415,345,338	39.51%	3.605%	1.424%	1.424%
Preferred Stock	\$0	0.00%	0.000%	0.000%	0.000%
Common Equity	\$26,665,503,451	60.49%	10.600%	6.412%	8.589%
TOTAL	\$44,080,848,789	100.00%		7.836%	10.013%

RATIO

DEBT COMPONENTS

Long term debt	1.1311%
Short term debt	0.0111%
Customer Deposits	0.0167%
Tax credits weighted	0.0269%
TOTAL DEBT	1.1858%

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	5.0921%
TAX CREDITS -WEIGHTED	0.1212%
TOTAL EQUITY	5.2133%
TOTAL	6.3991%
PRE-TAX EQUITY	6.9832%
PRE-TAX TOTAL	8.1690%

Note:

(a) Forecasted capital structure includes a deferred income tax proration adjustment consistent with FPSC Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.

(b) Cost rate for common equity represents FPL's mid-point return on equity approved by the FPSC in Order No. PSC-16-0560-AS-EI, Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI.

Florida Power & Light Company
Schedule E12 - Capacity Costs
Page 1 of 2

2022 Projection

Contract	Capacity MW	Term Start	Term End	Contract Type
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF

QF = Qualifying Facility

2022 Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
BS-NEG '91	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$1,507,380
Total	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$125,615	\$1,507,380

2022 Projection

<u>Contract</u>	<u>Counterparty</u>	<u>Identification</u>	<u>Contract Start Date</u>	<u>Contract End Date</u>
1	Solid Waste Authority (40MW)	Other Entity	January 1, 2012	April 1, 2032
2	Solid Waste Authority (70MW)	Other Entity	July 16, 2016	May 31, 2034
3	Central Alabama / Shell	Other Entity	November 2, 2009	May 31, 2023

2022 Capacity in MW

<u>Contract</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>
1	40	40	40	40	40	40	40	40	40	40	40	40
2	70	70	70	70	70	70	70	70	70	70	70	70
3	885	885	885	885	885	885	885	885	885	885	885	885
Total	995	995	995	995	995	995	995	995	995	995	995	995

2022 Capacity in Dollars

<u>Contract</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>
1												
2												
3												
Total												

Total Capacity Payments to Non-Cogenerators for 2022 ⁽¹⁾	91,885,200
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(1) Total short-term capacity payments do not include payments for the Solid Waste Authority - 70 MW unit. Capacity costs for this unit were recovered through the Energy Conservation Cost Recovery Clause in 2014, consistent with Commission Order No. PSC-11-0293-FOF-EU issued in Docket No. 110018-EU on July 6, 2011.

FPL - 2022 TEST YEAR - SEPARATION FACTORS

SUMMARY

DEMAND

E101 - Transmission	0.902581
E102 - Non-Stratified Production	0.959314
E103INT - Intermediate Strata Production	0.954287
E103PEAK - Peaking Strata Production	0.951837
E104 - Distribution	1.000000

ENERGY

FPL201 - Total Sales	0.946390
FPL202 - Non-Stratified Sales	0.958917
FPL203INT - Intermediate Strata Sales	0.947558
FPL203PEAK - Peaking Strata Sales	0.957721

GENERAL PLANT

I900 - LABOR	0.969001
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JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E101-TRANSMISSION: 12CPDemand
December 2022 - Test Year

RATE CLASS	12 CP - KW	VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW				% OF TOTAL	
	@ METER	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	338,111	0.0000	0.4237	0.5763	1.0208	1.0355	1.0645	0	148,343	207,424	355,767	1.4321%	1.5867%
CILC-1G	15,748	0.0000	0.0180	0.9820	1.0208	1.0355	1.0645	0	293	16,462	16,756	0.0674%	0.0747%
CILC-1T	184,861	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	188,715	0	0	188,715	0.7597%	0.8417%
GS(T)-1	1,599,867	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	1,703,043	1,703,043	6.8556%	7.5955%
GSCU-1	8,298	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	8,833	8,833	0.0356%	0.0394%
GSD(T)-1	4,574,458	0.0000	0.0035	0.9965	1.0208	1.0355	1.0645	0	16,473	4,852,533	4,869,006	19.6002%	21.7157%
GSLD(T)-1	1,687,046	0.0000	0.0585	0.9415	1.0208	1.0355	1.0645	0	102,180	1,690,807	1,792,986	7.2177%	7.9967%
GSLD(T)-2	536,952	0.0000	0.4306	0.5694	1.0208	1.0355	1.0645	0	239,452	325,432	564,884	2.2739%	2.5194%
GSLD(T)-3	130,551	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	133,273	0	0	133,273	0.5365%	0.5944%
MET	12,921	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	13,380	0	13,380	0.0539%	0.0597%
OL-1	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	0.0000%
OS-2	1,068	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	1,106	0	1,106	0.0045%	0.0049%
RS(T)-1	11,983,542	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	12,756,366	12,756,366	51.3507%	56.8932%
SL-1	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	0.0000%
SL-1M	114	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	122	122	0.0005%	0.0005%
SL-2	4,499	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	4,789	4,789	0.0193%	0.0214%
SL-2M	244	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	260	260	0.0010%	0.0012%
SST-DST	109	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	112	0	112	0.0005%	0.0005%
SST-TST	11,950	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,199	0	0	12,199	0.0491%	0.0544%
TOTAL RETAIL	21,090,338							334,187	521,339	21,566,071	22,421,597	90.2581%	
FKEC	130,152	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	132,866	0	0	132,866	0.5348%	
FPUC (INT)	12,721	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,986	0	0	12,986	0.0523%	
FPUC (PEAK)	9,719	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	9,922	0	0	9,922	0.0399%	
G - FPU (INT)	30,367	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	31,000	0	0	31,000	0.1248%	
G - FPU (PEAK)	20,729	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	21,161	0	0	21,161	0.0852%	
HOMESTEAD	4,082	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	4,167	0	0	4,167	0.0168%	
HOMESTEAD (INT)	8,326	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	8,500	0	0	8,500	0.0342%	
JEA (INT)	32,653	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	33,333	0	0	33,333	0.1342%	
LCEC	791,723	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	808,230	0	0	808,230	3.2535%	
MOORE HAVEN	571	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	583	0	0	583	0.0023%	
NEW SMRYNA BCH	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
NEW SMRYNA BCH (INT)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
QUINCY	3,102	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	3,167	0	0	3,167	0.0127%	
WAUCHULA	1,878	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,917	0	0	1,917	0.0077%	
TRANS-SERV	1,324,609	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,352,226	0	0	1,352,226	5.4434%	
TOTAL WHOLESALE	2,370,630							2,420,056	0	0	2,420,056	9.7419%	
TOTAL FPL	23,460,968							2,754,244	521,339	21,566,071	24,841,653	100.0000%	
JURIS SEPARATION FACTOR												0.902581	

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E102 - NON-STRATIFIED PRODUCTION: 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	338,111	0	338,111	0.0000	0.4237	0.5763	1.0208	1.0355	1.0645	0	148,343	207,424	355,767	1.5222%	1.5867%
CILC-1G	15,748	0	15,748	0.0000	0.0180	0.9820	1.0208	1.0355	1.0645	0	293	16,462	16,756	0.0717%	0.0747%
CILC-1T	184,861	0	184,861	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	188,715	0	0	188,715	0.8074%	0.8417%
GS(T)-1	1,599,867	0	1,599,867	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	1,703,043	1,703,043	7.2865%	7.5955%
GSCU-1	8,298	0	8,298	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	8,833	8,833	0.0378%	0.0394%
GSD(T)-1	4,574,458	0	4,574,458	0.0000	0.0035	0.9965	1.0208	1.0355	1.0645	0	16,473	4,852,533	4,869,006	20.8322%	21.7157%
GSLD(T)-1	1,687,046	0	1,687,046	0.0000	0.0585	0.9415	1.0208	1.0355	1.0645	0	102,180	1,690,807	1,792,986	7.6713%	7.9967%
GSLD(T)-2	536,952	0	536,952	0.0000	0.4306	0.5694	1.0208	1.0355	1.0645	0	239,452	325,432	564,884	2.4169%	2.5194%
GSLD(T)-3	130,551	0	130,551	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	133,273	0	0	133,273	0.5702%	0.5944%
MET	12,921	0	12,921	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	13,380	0	13,380	0.0572%	0.0597%
OL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	0.0000%
OS-2	1,068	0	1,068	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	1,106	0	1,106	0.0047%	0.0049%
RS(T)-1	11,983,542	0	11,983,542	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	12,756,366	12,756,366	54.5785%	56.8932%
SL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	0.0000%
SL-1M	114	0	114	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	122	122	0.0005%	0.0005%
SL-2	4,499	0	4,499	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	4,789	4,789	0.0205%	0.0214%
SL-2M	244	0	244	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	260	260	0.0011%	0.0012%
SST-DST	109	0	109	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	112	0	112	0.0005%	0.0005%
SST-TST	11,950	0	11,950	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,199	0	0	12,199	0.0522%	0.0544%
TOTAL RETAIL	21,090,338	0	21,090,338							334,187	521,339	21,566,071	22,421,597	95.9314%	100.0000%
FKEC	130,152	0	130,152	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	132,866	0	0	132,866	0.5685%	
FPUC (INT)	12,721	(12,721)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
FPUC (PEAK)	9,719	(9,719)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
G - FPU (INT)	30,367	(30,367)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
G - FPU (PEAK)	20,729	(20,729)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
HOMESTEAD	4,082	0	4,082	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	4,167	0	0	4,167	0.0178%	
HOMESTEAD (INT)	8,326	(8,326)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
JEA (INT)	32,653	(32,653)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
LCEC	791,723	0	791,723	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	808,230	0	0	808,230	3.4580%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	583	0	0	583	0.0025%	
NEW SMYRNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
NEW SMYRNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
QUINCY	3,102	0	3,102	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	3,167	0	0	3,167	0.0135%	
WAUCHULA	1,878	0	1,878	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,917	0	0	1,917	0.0082%	
TOTAL WHOLESALE	1,046,022	(114,514)	931,507							950,929	0	0	950,929	4.0686%	
TOTAL FPL	22,136,360	(114,514)	22,021,845							1,285,116	521,339	21,566,071	23,372,526	100.0000%	
JURIS SEPARATION FACTOR														0.959314	

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103INT - INTERMEDIATE STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	338,111	0	338,111	0.0000	0.4237	0.5763	1.0208	1.0355	1.0645	0	148,343	207,424	355,767	355,767	1.5142%	1.5867%
CILC-1G	15,748	0	15,748	0.0000	0.0180	0.9820	1.0208	1.0355	1.0645	0	293	16,462	16,756	16,756	0.0713%	0.0747%
CILC-1T	184,861	0	184,861	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	188,715	0	0	188,715	188,715	0.8032%	0.8417%
GS(T)-1	1,599,867	0	1,599,867	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	1,703,043	1,703,043	1,703,043	7.2483%	7.5955%
GSCU-1	8,298	0	8,298	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	8,833	8,833	8,833	0.0376%	0.0394%
GSD(T)-1	4,574,458	0	4,574,458	0.0000	0.0035	0.9965	1.0208	1.0355	1.0645	0	16,473	4,852,533	4,869,006	4,869,006	20.7230%	21.7157%
GSLD(T)-1	1,687,046	0	1,687,046	0.0000	0.0585	0.9415	1.0208	1.0355	1.0645	0	102,180	1,690,807	1,792,986	1,792,986	7.6311%	7.9967%
GSLD(T)-2	536,952	0	536,952	0.0000	0.4306	0.5694	1.0208	1.0355	1.0645	0	239,452	325,432	564,884	564,884	2.4042%	2.5194%
GSLD(T)-3	130,551	0	130,551	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	133,273	0	0	133,273	133,273	0.5672%	0.5944%
MET	12,921	0	12,921	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	13,380	0	13,380	13,380	0.0569%	0.0597%
OL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	0.0000%
OS-2	1,068	0	1,068	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	1,106	0	1,106	1,106	0.0047%	0.0049%
RS(T)-1	11,983,542	0	11,983,542	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	12,756,366	12,756,366	12,756,366	54.2925%	56.8932%
SL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	0.0000%
SL-1M	114	0	114	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	122	122	122	0.0005%	0.0005%
SL-2	4,499	0	4,499	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	4,789	4,789	4,789	0.0204%	0.0214%
SL-2M	244	0	244	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	260	260	260	0.0011%	0.0012%
SST-DST	109	0	109	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	112	0	112	112	0.0005%	0.0005%
SST-TST	11,950	0	11,950	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,199	0	0	12,199	12,199	0.0519%	0.0544%
TOTAL RETAIL	21,090,338	0	21,090,338							334,187	521,339	21,566,071	22,421,597	22,421,597	95.4287%	100.0000%
FKEC	130,152	0	130,152	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	132,866	0	0	132,866	132,866	0.5655%	
FPUC (INT)	12,721	0	12,721	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,986	0	0	12,986	18,631	0.0793%	
FPUC (PEAK)	9,719	(9,719)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
G - FPU (INT)	30,367	0	30,367	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	31,000	0	0	31,000	44,476	0.1893%	
G - FPU (PEAK)	20,729	(20,729)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
HOMESTEAD	4,082	0	4,082	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	4,167	0	0	4,167	4,167	0.0177%	
HOMESTEAD (INT)	8,326	0	8,326	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	8,500	0	0	8,500	12,195	0.0519%	
JEA (INT)	32,653	0	32,653	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	33,333	0	0	33,333	47,823	0.2035%	
LCEC	791,723	0	791,723	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	808,230	0	0	808,230	808,230	3.4399%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	583	0	0	583	583	0.0025%	
NEW SMYRNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
NEW SMYRNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
QUINCY	3,102	0	3,102	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	3,167	0	0	3,167	3,167	0.0135%	
WAUCHULA	1,878	0	1,878	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,917	0	0	1,917	1,917	0.0082%	
TOTAL WHOLESALE	1,046,022	(30,448)	1,015,574							1,036,748	0	0	1,036,748	1,074,053	4.5713%	
TOTAL FPL	22,136,360	(30,448)	22,105,912							1,370,935	521,339	21,566,071	23,458,345	23,495,650	100.0000%	
JURIS SEPARATION FACTOR															0.954287	

*CONTRACT ADJUSTMENTS ON FOLLOWING PAGE

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103INT - INTERMEDIATE STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
Contract Adjusted 12CP @ Generation -																
1) Contract Wholesale Customer 12 CP																
2) Intermediate System Capacity Net of Reserve Margin																
Intermediate Summer Capacity																
Divide By: System Capacity Including Reserve Margin (Calculation)																
Intermediate System Capacity Net of Reserve Margin																
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin																
3) Contract Adjusted 12CP @ Generation																
Total System 12CP Excluding All Stratified Contracts																
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin																
Total System 12CP Including Intermediate Stratified Contracts																
Contract Adjusted 12CP @ Generation																

Line No.	Source/Formula	FPUC (INT) Amount	G - FPU (INT) Amount	HOMESTEAD (INT) Amount	JEA (INT) Amount
1	Load Forecast * Loss Factor	12,986	31,000	8,500	33,333
2					
3	2020-2029 TYSP	19,652,000	19,652,000	19,652,000	19,652,000
4		120.0%	120.0%	120.0%	120.0%
5	L3 / L4	16,376,667	16,376,667	16,376,667	16,376,667
6	L1 / L5	0.000793	0.001893	0.000519	0.002035
7					
8		23,372,526	23,372,526	23,372,526	23,372,526
9	1 - Sum L6	0.99476	0.99476	0.99476	0.99476
10	L8 / L9	23,495,650	23,495,650	23,495,650	23,495,650
11	L6 * L11	18,631	44,476	12,195	47,823

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103PK - PEAKING STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	338,111	0	338,111	0.0000	0.4237	0.5763	1.0208	1.0355	1.0645	0	148,343	207,424	355,767	355,767	1.5103%	1.5867%
CILC-1G	15,748	0	15,748	0.0000	0.0180	0.9820	1.0208	1.0355	1.0645	0	293	16,462	16,756	16,756	0.0711%	0.0747%
CILC-1T	184,861	0	184,861	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	188,715	0	0	188,715	188,715	0.8011%	0.8417%
GS(T)-1	1,599,867	0	1,599,867	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	1,703,043	1,703,043	1,703,043	7.2297%	7.5955%
GSCU-1	8,298	0	8,298	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	8,833	8,833	8,833	0.0375%	0.0394%
GSD(T)-1	4,574,458	0	4,574,458	0.0000	0.0035	0.9965	1.0208	1.0355	1.0645	0	16,473	4,852,533	4,869,006	4,869,006	20.6698%	21.7157%
GSLD(T)-1	1,687,046	0	1,687,046	0.0000	0.0585	0.9415	1.0208	1.0355	1.0645	0	102,180	1,690,807	1,792,986	1,792,986	7.6116%	7.9967%
GSLD(T)-2	536,952	0	536,952	0.0000	0.4306	0.5694	1.0208	1.0355	1.0645	0	239,452	325,432	564,884	564,884	2.3980%	2.5194%
GSLD(T)-3	130,551	0	130,551	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	133,273	0	0	133,273	133,273	0.5658%	0.5944%
MET	12,921	0	12,921	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	13,380	0	13,380	13,380	0.0568%	0.0597%
OL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	0.0000%
OS-2	1,068	0	1,068	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	1,106	0	1,106	1,106	0.0047%	0.0049%
RS(T)-1	11,983,542	0	11,983,542	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	12,756,366	12,756,366	12,756,366	54.1531%	56.8932%
SL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	0.0000%
SL-1M	114	0	114	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	122	122	122	0.0005%	0.0005%
SL-2	4,499	0	4,499	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	4,789	4,789	4,789	0.0203%	0.0214%
SL-2M	244	0	244	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	260	260	260	0.0011%	0.0012%
SST-DST	109	0	109	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	112	0	112	112	0.0005%	0.0005%
SST-TST	11,950	0	11,950	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,199	0	0	12,199	12,199	0.0518%	0.0544%
TOTAL RETAIL	21,090,338	0	21,090,338							334,187	521,339	21,566,071	22,421,597	22,421,597	95.1837%	100.0000%
FKEC	130,152	0	130,152	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	132,866	0	0	132,866	132,866	0.5640%	
FPUC (INT)	12,721	(12,721)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
FPUC (PEAK)	9,719	0	9,719	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	9,922	0	0	9,922	58,606	0.2488%	
G - FPU (INT)	30,367	(30,367)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
G - FPU (PEAK)	20,729	0	20,729	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	21,161	0	0	21,161	124,996	0.5306%	
HOMESTEAD	4,082	0	4,082	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	4,167	0	0	4,167	4,167	0.0177%	
HOMESTEAD (INT)	8,326	(8,326)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
JEA (INT)	32,653	(32,653)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
LCEC	791,723	0	791,723	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	808,230	0	0	808,230	808,230	3.4311%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	583	0	0	583	583	0.0025%	
NEW SMYRNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
NEW SMYRNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
QUINCY	3,102	0	3,102	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	3,167	0	0	3,167	3,167	0.0134%	
WAUCHULA	1,878	0	1,878	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,917	0	0	1,917	1,917	0.0081%	
TOTAL WHOLESALE	1,046,022	(84,066)	961,955							982,011	0	0	982,011	1,134,531	4.8163%	
TOTAL FPL	22,136,360	(84,066)	22,052,293							1,316,199	521,339	21,566,071	23,403,608	23,556,128	100.0000%	
JURIS SEPARATION FACTOR															0.951837	

*CONTRACT ADJUSTMENTS ON FOLLOWING PAGE

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103PK - PEAKING STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL

Contract Adjusted 12CP @ Generation -

- 1) Contract Wholesale Customer 12 CP
- 2) Peaking System Capacity Net of Reserve Margin
 - Peaking Summer Capacity
 - Divide By: System Capacity Including Reserve Margin (Calculation)
 - Peaking System Capacity Net of Reserve Margin
- Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin
- 3) Contract Adjusted 12CP @ Generation
 - Total System 12CP Excluding All Stratified Contracts
 - Contribution (Excluding Peaking Stratified Contracts) to Other Production System Capacity Net of Reserve Margin
 - Total System 12CP Including Intermediate Stratified Contracts

Contract Adjusted 12CP @ Generation

Line No.	Source/Formula	FPUC (PEAK)	G - FPU (PEAK)
		Amount	Amount
1	Load Forecast * Loss Factor	9,922	21,161
2			
3	2020-2029 TYSP	4,785,500	4,785,500
4		120.0%	120.0%
5	L3 / L4	3,987,917	3,987,917
6	L1 / L5	0.00249	0.00531
7			
8		23,372,526	23,372,526
9	1 - Sum L6	0.99221	0.99221
10	L8 / L9	23,556,128	23,556,128
11	L6 * L11	58,606	124,996

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E104 - DISTRIBUTION: Group Non-Coincident Peak (GNCP) Demand
December 2022 - Test Year

RATE CLASS	MAX GNCP	VOLTAGE LEVEL % - DEMAND		LOSS EXPANSION FACTORS		MAX GNCP @ GENERATION			% OF TOTAL	
	@ METER	PRIMARY	SECOND	PRIMARY	SECOND	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	365,677	0.4237	0.5763	1.0355	1.0645	160,438	224,335	384,773	1.4305%	1.4305%
CILC-1G	17,146	0.0180	0.9820	1.0355	1.0645	319	17,923	18,242	0.0678%	0.0678%
CILC-1T	215,303	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	0.0000%
GS(T)-1	1,826,197	0.0000	1.0000	1.0355	1.0645	0	1,943,969	1,943,969	7.2272%	7.2272%
GSCU-1	9,315	0.0000	1.0000	1.0355	1.0645	0	9,916	9,916	0.0369%	0.0369%
GSD(T)-1	5,074,617	0.0035	0.9965	1.0355	1.0645	18,274	5,383,096	5,401,370	20.0809%	20.0809%
GSLD(T)-1	1,948,749	0.0585	0.9415	1.0355	1.0645	118,030	1,953,093	2,071,124	7.6999%	7.6999%
GSLD(T)-2	582,880	0.4306	0.5694	1.0355	1.0645	259,934	353,267	613,201	2.2797%	2.2797%
GSLD(T)-3	167,370	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	0.0000%
MET	15,793	1.0000	0.0000	1.0355	1.0645	16,355	0	16,355	0.0608%	0.0608%
OL-1	24,408	0.0000	1.0000	1.0355	1.0645	0	25,982	25,982	0.0966%	0.0966%
OS-2	7,281	1.0000	0.0000	1.0355	1.0645	7,540	0	7,540	0.0280%	0.0280%
RS(T)-1	15,259,164	0.0000	1.0000	1.0355	1.0645	0	16,243,234	16,243,234	60.3882%	60.3882%
SL-1	121,913	0.0000	1.0000	1.0355	1.0645	0	129,775	129,775	0.4825%	0.4825%
SL-1M	7,342	0.0000	1.0000	1.0355	1.0645	0	7,816	7,816	0.0291%	0.0291%
SL-2	6,497	0.0000	1.0000	1.0355	1.0645	0	6,916	6,916	0.0257%	0.0257%
SL-2M	486	0.0000	1.0000	1.0355	1.0645	0	517	517	0.0019%	0.0019%
SST-DST	16,698	1.0000	0.0000	1.0355	1.0645	17,291	0	17,291	0.0643%	0.0643%
SST-TST	46,871	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	0.0000%
TOTAL RETAIL	25,713,708					598,180	26,299,841	26,898,021	100.0000%	100.0000%
FKEC	158,742	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
FPUC (INT)	13,715	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
FPUC (PEAK)	30,420	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
G - FPU (INT)	30,368	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
G - FPU (PEAK)	30,891	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
HOMESTEAD	24,490	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
HOMESTEAD (INT)	49,959	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
JEA (INT)	195,916	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
LCEC	1,011,459	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
MOORE HAVEN	3,919	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
NEW SMYRNA BCH	0	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	0	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
NEW SMYRNA BCH (PEAK)	0	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
QUINCY	18,613	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
WAUCHULA	13,715	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
TOTAL WHOLESALE	1,582,208					0	0	0	0.0000%	
TOTAL FPL	27,295,916					598,180	26,299,841	26,898,021	100.0000%	
JURIS SEPARATION FACTOR									1.000000	

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E201 - TOTAL SALES: Total Annual Energy
December 2022 - Test Year

RATE CLASS	MWH SALES	VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,535,287	0.0000	0.4171	0.5829	1.0164	1.0274	1.0491	0	1,086,378	1,550,459	2,636,837	1.9507%	2.0611%
CILC-1G	112,191	0.0000	0.0170	0.9830	1.0164	1.0274	1.0491	0	1,964	115,692	117,656	0.0870%	0.0920%
CILC-1T	1,504,497	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,529,183	0	0	1,529,183	1.1312%	1.1953%
GS(T)-1	8,368,517	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	8,779,240	8,779,240	6.4946%	6.8625%
GSCU-1	69,414	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	72,821	72,821	0.0539%	0.0569%
GSD(T)-1	28,295,907	0.0000	0.0037	0.9963	1.0164	1.0274	1.0491	0	106,198	29,576,223	29,682,421	21.9581%	23.2020%
GSLD(T)-1	10,335,975	0.0000	0.0574	0.9426	1.0164	1.0274	1.0491	0	609,862	10,220,553	10,830,415	8.0120%	8.4659%
GSLD(T)-2	3,825,387	0.0000	0.4313	0.5687	1.0164	1.0274	1.0491	0	1,695,115	2,282,319	3,977,434	2.9424%	3.1091%
GSLD(T)-3	960,789	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	976,554	0	0	976,554	0.7224%	0.7633%
MET	84,975	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	87,306	0	87,306	0.0646%	0.0682%
OL-1	90,638	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	95,087	95,087	0.0703%	0.0743%
OS-2	9,901	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	10,173	0	10,173	0.0075%	0.0080%
RS(T)-1	65,315,939	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	68,521,615	68,521,615	50.6902%	53.5616%
SL-1	452,711	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	474,930	474,930	0.3513%	0.3712%
SL-1M	26,569	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	27,873	27,873	0.0206%	0.0218%
SL-2	37,681	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	39,531	39,531	0.0292%	0.0309%
SL-2M	3,001	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	3,148	3,148	0.0023%	0.0025%
SST-DST	1,411	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	1,450	0	1,450	0.0011%	0.0011%
SST-TST	65,711	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	66,789	0	0	66,789	0.0494%	0.0522%
TOTAL RETAIL	122,096,501							2,572,525	3,598,445	121,759,492	127,930,462	94.6390%	100.0000%
FKEC	799,412	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	812,528	0	0	812,528	0.6011%	
FPUC (INT)	101,728	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	103,398	0	0	103,398	0.0765%	
FPUC (PEAK)	53,455	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	54,332	0	0	54,332	0.0402%	
G - FPU (INT)	181,040	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	184,010	0	0	184,010	0.1361%	
G - FPU (PEAK)	105,541	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	107,273	0	0	107,273	0.0794%	
HOMESTEAD	31,630	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	32,149	0	0	32,149	0.0238%	
HOMESTEAD (INT)	228,809	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	232,563	0	0	232,563	0.1720%	
JEA (INT)	1,061,600	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,079,019	0	0	1,079,019	0.7982%	
LCEC	4,363,325	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,434,918	0	0	4,434,918	3.2808%	
MOORE HAVEN	17,408	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,693	0	0	17,693	0.0131%	
NEW SMYRNA BCH	17,692	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,982	0	0	17,982	0.0133%	
NEW SMYRNA BCH (INT)	312	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	317	0	0	317	0.0002%	
NEW SMYRNA BCH (PEAK)	4,888	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,968	0	0	4,968	0.0037%	
QUINCY	99,134	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	100,761	0	0	100,761	0.0745%	
WAUCHULA	63,867	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	64,915	0	0	64,915	0.0480%	
TOTAL WHOLESALE	7,129,840							7,246,825	0	0	7,246,825	5.3610%	
TOTAL FPL	129,226,341							9,819,351	3,598,445	121,759,492	135,177,288	100.0000%	
JURIS SEPARATION FACTOR												0.946390	

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E202 - NON-STRATIFIED SALES: Total Annual Energy
December 2022 - Test Year

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,535,287	0	2,535,287	0.0000	0.4171	0.5829	1.0164	1.0274	1.0491	0	1,086,378	1,550,459	2,636,837	1.9765%	2.0611%
CILC-1G	112,191	0	112,191	0.0000	0.0170	0.9830	1.0164	1.0274	1.0491	0	1,964	115,692	117,656	0.0882%	0.0920%
CILC-1T	1,504,497	0	1,504,497	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,529,183	0	0	1,529,183	1.1462%	1.1953%
GS(T)-1	8,368,517	0	8,368,517	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	8,779,240	8,779,240	6.5806%	6.8625%
GSCU-1	69,414	0	69,414	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	72,821	72,821	0.0546%	0.0569%
GSD(T)-1	28,295,907	0	28,295,907	0.0000	0.0037	0.9963	1.0164	1.0274	1.0491	0	106,198	29,576,223	29,682,421	22.2488%	23.2020%
GSLD(T)-1	10,335,975	0	10,335,975	0.0000	0.0574	0.9426	1.0164	1.0274	1.0491	0	609,862	10,220,553	10,830,415	8.1181%	8.4659%
GSLD(T)-2	3,825,387	0	3,825,387	0.0000	0.4313	0.5687	1.0164	1.0274	1.0491	0	1,695,115	2,282,319	3,977,434	2.9813%	3.1091%
GSLD(T)-3	960,789	0	960,789	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	976,554	0	0	976,554	0.7320%	0.7633%
MET	84,975	0	84,975	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	87,306	0	87,306	0.0654%	0.0682%
OL-1	90,638	0	90,638	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	95,087	95,087	0.0713%	0.0743%
OS-2	9,901	0	9,901	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	10,173	0	10,173	0.0076%	0.0080%
RS(T)-1	65,315,939	0	65,315,939	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	68,521,615	68,521,615	51.3611%	53.5616%
SL-1	452,711	0	452,711	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	474,930	474,930	0.3560%	0.3712%
SL-1M	26,569	0	26,569	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	27,873	27,873	0.0209%	0.0218%
SL-2	37,681	0	37,681	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	39,531	39,531	0.0296%	0.0309%
SL-2M	3,001	0	3,001	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	3,148	3,148	0.0024%	0.0025%
SST-DST	1,411	0	1,411	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	1,450	0	1,450	0.0011%	0.0011%
SST-TST	65,711	0	65,711	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	66,789	0	0	66,789	0.0501%	0.0522%
TOTAL RETAIL	122,096,501	0	122,096,501							2,572,525	3,598,445	121,759,492	127,930,462	95.8917%	100.0000%
FKEC	799,412	0	799,412	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	812,528	0	0	812,528	0.6090%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
G - FPU (INT)	181,040	(181,040)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
G - FPU (PEAK)	105,541	(105,541)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
HOMESTEAD	31,630	0	31,630	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	32,149	0	0	32,149	0.0241%	
HOMESTEAD (INT)	228,809	(228,809)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
JEA (INT)	1,061,600	(1,061,600)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
LCEC	4,363,325	0	4,363,325	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,434,918	0	0	4,434,918	3.3242%	
MOORE HAVEN	17,408	0	17,408	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,693	0	0	17,693	0.0133%	
NEW SMRYNA BCH	17,692	0	17,692	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,982	0	0	17,982	0.0135%	
NEW SMRYNA BCH (PEAK)	4,888	(4,888)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
NEW SMRYNA BCH (INT)	312	(312)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
QUINCY	99,134	0	99,134	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	100,761	0	0	100,761	0.0755%	
WAUCHULA	63,867	0	63,867	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	64,915	0	0	64,915	0.0487%	
TOTAL WHOLESALE	7,129,840	(1,737,372)	5,392,467							5,480,946	0	0	5,480,946	4.1083%	
TOTAL FPL	129,226,341	(1,737,372)	127,488,969							8,053,472	3,598,445	121,759,492	133,411,409	100.0000%	
JURIS SEPARATION FACTOR														0.958917	

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E203INT - INTERMEDIATE STRATA SALES (CONTRACT ADJUSTED): Total Annual Energy
December 2022 - Test Year

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,535,287	0	2,535,287	0.0000	0.4171	0.5829	1.0164	1.0274	1.0491	0	1,086,378	1,550,459	2,636,837	1.9531%	2.0611%
CILC-1G	112,191	0	112,191	0.0000	0.0170	0.9830	1.0164	1.0274	1.0491	0	1,964	115,692	117,656	0.0871%	0.0920%
CILC-1T	1,504,497	0	1,504,497	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,529,183	0	0	1,529,183	1.1326%	1.1953%
GS(T)-1	8,368,517	0	8,368,517	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	8,779,240	8,779,240	6.5026%	6.8625%
GSCU-1	69,414	0	69,414	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	72,821	72,821	0.0539%	0.0569%
GSD(T)-1	28,295,907	0	28,295,907	0.0000	0.0037	0.9963	1.0164	1.0274	1.0491	0	106,198	29,576,223	29,682,421	21.9852%	23.2020%
GSLD(T)-1	10,335,975	0	10,335,975	0.0000	0.0574	0.9426	1.0164	1.0274	1.0491	0	609,862	10,220,553	10,830,415	8.0219%	8.4659%
GSLD(T)-2	3,825,387	0	3,825,387	0.0000	0.4313	0.5687	1.0164	1.0274	1.0491	0	1,695,115	2,282,319	3,977,434	2.9460%	3.1091%
GSLD(T)-3	960,789	0	960,789	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	976,554	0	0	976,554	0.7233%	0.7633%
MET	84,975	0	84,975	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	87,306	0	87,306	0.0647%	0.0682%
OL-1	90,638	0	90,638	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	95,087	95,087	0.0704%	0.0743%
OS-2	9,901	0	9,901	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	10,173	0	10,173	0.0075%	0.0080%
RS(T)-1	65,315,939	0	65,315,939	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	68,521,615	68,521,615	50.7527%	53.5616%
SL-1	452,711	0	452,711	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	474,930	474,930	0.3518%	0.3712%
SL-1M	26,569	0	26,569	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	27,873	27,873	0.0206%	0.0218%
SL-2	37,681	0	37,681	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	39,531	39,531	0.0293%	0.0309%
SL-2M	3,001	0	3,001	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	3,148	3,148	0.0023%	0.0025%
SST-DST	1,411	0	1,411	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	1,450	0	1,450	0.0011%	0.0011%
SST-TST	65,711	0	65,711	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	66,789	0	0	66,789	0.0495%	0.0522%
TOTAL RETAIL	122,096,501	0	122,096,501							2,572,525	3,598,445	121,759,492	127,930,462	94.7558%	100.0000%
FKEC	799,412	0	799,412	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	812,528	0	0	812,528	0.6018%	
FPUC (INT)	101,728	0	101,728	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	103,398	0	0	103,398	0.0766%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
G - FPU (INT)	181,040	0	181,040	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	184,010	0	0	184,010	0.1363%	
G - FPU (PEAK)	105,541	(105,541)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
HOMESTEAD	31,630	0	31,630	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	32,149	0	0	32,149	0.0238%	
HOMESTEAD (INT)	228,809	0	228,809	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	232,563	0	0	232,563	0.1723%	
JEA (INT)	1,061,600	0	1,061,600	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,079,019	0	0	1,079,019	0.7992%	
LCEC	4,363,325	0	4,363,325	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,434,918	0	0	4,434,918	3.2849%	
MOORE HAVEN	17,408	0	17,408	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,693	0	0	17,693	0.0131%	
NEW SMRYNA BCH	17,692	0	17,692	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,982	0	0	17,982	0.0133%	
NEW SMRYNA BCH (INT)	312	0	312	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	317	0	0	317	0.0002%	
NEW SMRYNA BCH (PEAK)	4,888	(4,888)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
QUINCY	99,134	0	99,134	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	100,761	0	0	100,761	0.0746%	
WAUCHULA	63,867	0	63,867	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	64,915	0	0	64,915	0.0481%	
TOTAL WHOLESALE	7,129,840	(163,883)	6,965,957							7,080,253	0	0	7,080,253	5.2442%	
TOTAL FPL	129,226,341	(163,883)	129,062,458							9,652,779	3,598,445	121,759,492	135,010,716	100.0000%	
JURIS SEPARATION FACTOR														0.947558	

JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E203PK - PEAKING STRATA SALES (CONTRACT ADJUSTED): Total Annual Energy
December 2022 - Test Year

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,535,287	0	2,535,287	0.0000	0.4171	0.5829	1.0164	1.0274	1.0491	0	1,086,378	1,550,459	2,636,837	1.9740%	2.0611%
CILC-1G	112,191	0	112,191	0.0000	0.0170	0.9830	1.0164	1.0274	1.0491	0	1,964	115,692	117,656	0.0881%	0.0920%
CILC-1T	1,504,497	0	1,504,497	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,529,183	0	0	1,529,183	1.1448%	1.1953%
GS(T)-1	8,368,517	0	8,368,517	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	8,779,240	8,779,240	6.5724%	6.8625%
GSCU-1	69,414	0	69,414	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	72,821	72,821	0.0545%	0.0569%
GSD(T)-1	28,295,907	0	28,295,907	0.0000	0.0037	0.9963	1.0164	1.0274	1.0491	0	106,198	29,576,223	29,682,421	22.2210%	23.2020%
GSLD(T)-1	10,335,975	0	10,335,975	0.0000	0.0574	0.9426	1.0164	1.0274	1.0491	0	609,862	10,220,553	10,830,415	8.1079%	8.4659%
GSLD(T)-2	3,825,387	0	3,825,387	0.0000	0.4313	0.5687	1.0164	1.0274	1.0491	0	1,695,115	2,282,319	3,977,434	2.9776%	3.1091%
GSLD(T)-3	960,789	0	960,789	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	976,554	0	0	976,554	0.7311%	0.7633%
MET	84,975	0	84,975	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	87,306	0	87,306	0.0654%	0.0682%
OL-1	90,638	0	90,638	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	95,087	95,087	0.0712%	0.0743%
OS-2	9,901	0	9,901	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	10,173	0	10,173	0.0076%	0.0080%
RS(T)-1	65,315,939	0	65,315,939	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	68,521,615	68,521,615	51.2971%	53.5616%
SL-1	452,711	0	452,711	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	474,930	474,930	0.3555%	0.3712%
SL-1M	26,569	0	26,569	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	27,873	27,873	0.0209%	0.0218%
SL-2	37,681	0	37,681	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	39,531	39,531	0.0296%	0.0309%
SL-2M	3,001	0	3,001	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	3,148	3,148	0.0024%	0.0025%
SST-DST	1,411	0	1,411	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	1,450	0	1,450	0.0011%	0.0011%
SST-TST	65,711	0	65,711	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	66,789	0	0	66,789	0.0500%	0.0522%
TOTAL RETAIL	122,096,501	0	122,096,501							2,572,525	3,598,445	121,759,492	127,930,462	95.7721%	100.0000%
FKEC	799,412	0	799,412	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	812,528	0	0	812,528	0.6083%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	0	53,455	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	54,332	0	0	54,332	0.0407%	
G - FPU (INT)	181,040	(181,040)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
G - FPU (PEAK)	105,541	0	105,541	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	107,273	0	0	107,273	0.0803%	
HOMESTEAD	31,630	0	31,630	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	32,149	0	0	32,149	0.0241%	
HOMESTEAD (INT)	228,809	(228,809)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
JEA (INT)	1,061,600	(1,061,600)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
LCEC	4,363,325	0	4,363,325	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,434,918	0	0	4,434,918	3.3201%	
MOORE HAVEN	17,408	0	17,408	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,693	0	0	17,693	0.0132%	
NEW SMYRNA BCH	17,692	0	17,692	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,982	0	0	17,982	0.0135%	
NEW SMYRNA BCH (INT)	312	(312)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
NEW SMYRNA BCH (PEAK)	4,888	0	4,888	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,968	0	0	4,968	0.0037%	
QUINCY	99,134	0	99,134	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	100,761	0	0	100,761	0.0754%	
WAUCHULA	63,867	0	63,867	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	64,915	0	0	64,915	0.0486%	
TOTAL WHOLESALE	7,129,840	(1,573,489)	5,556,350							5,647,518	0	0	5,647,518	4.2279%	
TOTAL FPL	129,226,341	(1,573,489)	127,652,852							8,220,044	3,598,445	121,759,492	133,577,980	100.0000%	
JURISDICTIONAL SEPARATION F/														0.957721	

JURISDICTIONAL SEPARATION STUDY
SEP - Internal Factors Based on External Factors
December 2022 - Test Year

SEP - INTERNAL FACTORS BASED ON EXTERNAL FACTORS	ALLOCATOR	COMPANY PER BOOKS	SEPARATION FACTOR	JURISDICTIONAL	INTERNAL SEPARATION FACTOR
1900-LABOR-EXC-A&G					
L_INC100000 - STEAM O&M PAY - OPERAT SUPERV & ENG	BLENDED	1,153,822	0.958418	1,105,843	
L_INC101210 - STEAM O&M PAY - FUEL - NON RECOVERABLE OIL	BLENDED	164,993	0.953661	157,347	
L_INC102000 - STEAM O&M PAY - STEAM EXPENSES	BLENDED	2,376,106	0.959293	2,279,382	
L_INC105000 - STEAM O&M PAY - ELECTRIC EXPENSES	BLENDED	1,817,598	0.959284	1,743,591	
L_INC106000 - STEAM O&M PAY - MISC STEAM POWER EXPENSES	BLENDED	5,840,834	0.957388	5,591,944	
L_INC110000 - STEAM O&M PAY - MAINT SUPERV & ENG	BLENDED	1,035,263	0.958023	991,806	
L_INC111000 - STEAM O&M PAY - MAINT OF STRUCTURES	BLENDED	1,588,766	0.958673	1,523,106	
L_INC112000 - STEAM O&M PAY - MAINT OF BOILER PLANT	BLENDED	2,625,296	0.958172	2,515,484	
L_INC113000 - STEAM O&M PAY - MAINT OF ELECTRIC PLANT	BLENDED	1,275,054	0.955628	1,218,478	
L_INC114000 - STEAM O&M PAY - MAINT OF MISC STEAM PLT	BLENDED	575,362	0.958894	551,712	
L_INC117000 - NUCLEAR O&M PAY - OPER SUPERV & ENG	BLENDED	44,383,699	0.959454	42,584,109	
L_INC119000 - NUCLEAR O&M PAY - COOLANTS AND WATER	BLENDED	3,150,377	0.959647	3,023,250	
L_INC120000 - NUCLEAR O&M PAY - STEAM EXPENSES	BLENDED	44,301,329	0.959491	42,506,743	
L_INC123000 - NUCLEAR O&M PAY - ELECTRIC EXP	BLENDED	453	0.959307	434	
L_INC124000 - NUCLEAR O&M PAY - MISC NUCLEAR POWER EXP	BLENDED	33,952,424	0.958782	32,552,981	
L_INC128000 - NUCLEAR O&M PAY - MAINT SUPERVISION & ENGINEERING	BLENDED	197,627,071	0.959125	189,549,048	
L_INC129000 - NUCLEAR O&M PAY - MAINT OF STRUCTURES	BLENDED	163,170	0.959371	156,541	
L_INC130000 - NUCLEAR O&M PAY - MAINT OF REACTOR PLANT	BLENDED	75,875	0.960488	72,877	
L_INC131000 - NUCLEAR O&M PAY - MAINT OF ELECTRIC PLANT	BLENDED	539,172	0.959799	517,497	
L_INC132000 - NUCLEAR O&M PAY - MAINT OF MISC NUCLEAR PLANT	BLENDED	1,314	0.960592	1,263	
L_INC146000 - OTH PWR O&M PAY - OPERAT SUPERV & ENG	BLENDED	13,594,628	0.955052	12,983,578	
L_INC147200 - OTH PWR O&M PAY - FUEL N- RECOV EMISSIONS FEE	BLENDED	3,455,295	0.946412	3,270,134	
L_INC148000 - OTH PWR O&M PAY- GENERATION EXPENSES	BLENDED	10,164,639	0.954839	9,705,590	
L_INC149000 - OTH PWR O&M PAY - MISC OTHER POWER GENERATION EXPENSES	BLENDED	22,521,800	0.955252	21,513,987	
L_INC151000 - OTH PWR O&M PAY - MAINT SUPERV & ENG	BLENDED	8,603,614	0.952225	8,192,574	
L_INC152000 - OTH PWR O&M PAY - MAINT OF STRUCTURES	BLENDED	20,897,041	0.954161	19,939,149	
L_INC153000 - OTH PWR O&M PAY - MAINT GENERATING & ELECTRIC PLANT	BLENDED	16,551,151	0.948211	15,693,980	
L_INC154000 - OTH PWR O&M PAY - MAINT MISC OTHER PWR GENERAT	BLENDED	3,278,434	0.949195	3,111,873	
L_INC156000 - OTH PWR O&M PAY - SYSTEM CONTROL & LOAD DISPATCH	I340	868,289	0.955404	829,566	
L_INC157000 - OTH PWR O&M PAY - OTHER EXPENSES LOC 955	I340	1,511,611	0.955404	1,444,198	
L_INC260010 - TRANS O&M PAY - OPERATION SUPERV & ENGINEERING	E101	4,959,832	0.902581	4,476,649	
L_INC261000 - TRANS O&M PAY - LOAD DISPATCHING	E101	3,086,033	0.902581	2,785,394	
L_INC262000 - TRANS O&M PAY - STATION EXPENSES	E101	1,241,846	0.902581	1,120,866	
L_INC263000 - TRANS O&M PAY - OVERHEAD LINE EXPENSES	E101	61,150	0.902581	55,192	
L_INC266000 - TRANS O&M PAY - MISC TRANSMISSION EXPENSES	E101	3,961,791	0.902581	3,575,836	
L_INC268010 - TRANS O&M PAY - MAINT SUPERV & ENG	E101	1,964,589	0.902581	1,773,200	
L_INC269000 - TRANS O&M PAY - MAINT OF STRUCTURES	E101	3,239,591	0.902581	2,923,992	
L_INC270000 - TRANS O&M PAY - MAINT OF STATION EQ	E101	1,467,189	0.902581	1,324,256	
L_INC271000 - TRANS O&M PAY - MAINT OF OVERHEAD LINES	E101	1,366,419	0.902581	1,233,304	
L_INC272000 - TRANS O&M PAY - MAINT UNDERGROUND LINES	E101	16,452	0.902581	14,850	
L_INC380000 - DIST O&M PAY - OPERATION SUPERVISION AND ENGINEERING	E104	25,026,141	1.000000	25,026,141	
L_INC381000 - DIST O&M PAY - LOAD DISPATCHING	E104	4,523,619	1.000000	4,523,619	
L_INC382000 - DIST O&M PAY - SUBSTATION EXPENSES	E104	814,990	1.000000	814,990	
L_INC383000 - DIST O&M PAY - OVERHEAD LINE EXPENSES	I365T	4,971,521	1.000000	4,971,521	

JURISDICTIONAL SEPARATION STUDY
SEP - Internal Factors Based on External Factors
December 2022 - Test Year

SEP - INTERNAL FACTORS BASED ON EXTERNAL FACTORS	ALLOCATOR	COMPANY PER BOOKS	SEPARATION FACTOR	JURISDICTIONAL	INTERNAL SEPARATION FACTOR
L_INC384000 - DIST O&M PAY - UNDERGROUND LINE EXP	I367T	1,622,213	1.000000	1,622,213	
L_INC385000 - DIST O&M PAY - STREET LIGHTING AND SIGNAL SYSTEM EXPENSES	E508	1,752,435	1.000000	1,752,435	
L_INC386000 - DIST O&M PAY - METER EXPENSES	E325	(947,124)	0.996349	(943,666)	
L_INC387000 - DIST O&M PAY - CUSTOMER INSTALLATIONS EXP	E309	1,116,576	1.000000	1,116,576	
L_INC388000 - DIST O&M PAY - MISC DISTRIBUTION EXPENSES	E104	26,519,128	1.000000	26,519,128	
L_INC390000 - DIST O&M PAY - MAINT SUPERV & ENG	E104	16,712,775	1.000000	16,712,775	
L_INC391000 - DIST O&M PAY - MAINT OF STRUCTURES	E104	1,984	1.000000	1,984	
L_INC392000 - DIST O&M PAY - MAINT OF STATION EQ	E104	3,110,512	1.000000	3,110,512	
L_INC393000 - DIST O&M PAY - MAINT OF OVERHEAD LINES	I365T	24,700,469	1.000000	24,700,469	
L_INC394000 - DIST O&M PAY - MAINT UNDERGROUND LINES	I367T	10,499,962	1.000000	10,499,962	
L_INC395000 - DIST O&M PAY - MAINT OF LINE TRANSFORMERS	E104	18,268	1.000000	18,268	
L_INC396000 - DIST O&M PAY - MAINT OF STREET LIGHTING & SIGNAL SYSTEMS	E508	4,208,675	1.000000	4,208,675	
L_INC397000 - DIST O&M PAY - MAINT OF METERS	E325	3,605,912	0.996349	3,592,747	
L_INC398000 - DIST O&M PAY - MAINT OF MISC DISTRI PLT	E104	17,274	1.000000	17,274	
L_INC401000 - CUST ACCT O&M PAY - SUPERVISION	I540	5,570,046	0.999978	5,569,923	
L_INC402000 - CUST ACCT O&M PAY - METER READING EXP	E330	14,936,781	0.999995	14,936,705	
L_INC403000 - CUST ACCT O&M PAY - CUST REC & COLLECT	E356	41,341,974	1.000000	41,341,974	
L_INC407000 - CUST SERV & INFO PAY - SUPERVISION	E356	124,688	1.000000	124,688	
L_INC408000 - CUST SERV & INFO PAY - CUST ASSIST EXP	E356	11,093,092	1.000000	11,093,092	
L_INC409000 - CUST SERV & INFO PAY - INFO & INST ADV - GENERAL	E356	2,067	1.000000	2,067	
L_INC410000 - CUST SERV & INFO PAY - MISC CUST SERV & INF	E356	5,226,321	1.000000	5,226,321	
L_INC510000 - DEMONSTRATING AND SELLING EXPENSES	E356	235,560	1.000000	235,560	
L_INC516000 - MISC AND SELLING EXPENSES	E356	578,265	1.000000	578,265	
Total I900-LABOR-EXC-A&G		672,843,496		651,985,828	0.969001

Schedule 1

**GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2020 - DECEMBER 2020**

1. Estimated over/(under)-recovery for the period JANUARY 2020 - DECEMBER 2020 (Schedule E-1B, Line 9, filed July 27, 2020) approved in FPSC Order No. PSC-2020-0439-FOF-EI issued on November 16, 2020)		\$ (9,968,285)
	4	
	5	
2. Actual over/(under)-recovery for the period January 2020 - December 2020 (December 2020 Schedule A-2, page 2 of 3, "Period-to-Date", Lines 7 + 8 + 12, included in Exhibit RLH-2)	1-23	<u>(3,882,605)</u>
3. Amount to be refunded/(recovered) in the January 2022 - December 2022 projection period (Line 2 - Line 1)		<u>\$ 6,085,680</u>

Schedule 2

**GULF POWER COMPANY
FUEL VARIANCES SUMMARY
ACTUAL vs. ESTIMATED
FOR THE PERIOD
JANUARY 2020 - DECEMBER 2020**

	2020 Final True-Up	2020 Actual/ Estimated	Difference	Percent Variance
Fuel Cost of System Generation (incl. adj.)	190,842,864	215,050,454	(24,207,590)	-11.26%
Fuel Cost of Hedging Settlement	1,605,420	1,605,420	0	0.00%
Stratified Revenue Credit	(5,431,727)	(1,952,040)	(3,479,687)	178.26%
Total Fuel Cost & Gains on Power Sales	(56,082,677)	(85,357,812)	29,275,136	-34.30%
Total Cost of Purchased Power	177,881,592	180,925,065	(3,043,473)	-1.68%
TOTAL FUEL & NET POWER TRANSACTIONS	308,815,472	310,271,087	(1,455,615)	-0.47%
Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	305,319,719	301,314,456	4,005,263	1.33%
True-Up Provision	(666,833)	(666,833)	0	0.00%
Incentive Provision	(10,377)	(10,377)	0	0.00%
FUEL REVENUE APPLICABLE TO PERIOD	304,642,509	300,637,246	4,005,263	1.33%
Fuel Cost of System Generation (MWH)	7,666,983	8,933,598	(1,266,615)	-14.18%
Total Fuel Cost & Gains on Power Sales (MWH)	3,065,477	4,668,264	(1,602,787)	-34.33%
Total Cost of Purchased Power (MWH)	7,073,921	7,549,910	(475,989)	-6.30%
TOTAL FUEL & NET POWER TRANSACTIONS (MWH)	17,806,382	21,151,772	(3,345,391)	-15.82%
Fuel Cost of System Generation (¢/kWh)	2.489	2.407	0.082	3.40%
Total Fuel Cost & Gains on Power Sales (¢/kWh)	(1.829)	(1.828)	(0.001)	0.06%
Total Cost of Purchased Power (¢/kWh)	2.515	2.396	0.118	4.93%
TOTAL FUEL & NET POWER TRANSACTIONS (¢/kWh)	1.734	1.467	0.199	13.58%
COMPARATIVE DATA BY MAJOR FUEL TYPE				
<u>COAL + GAS B.L. + OIL B.L.</u>				
Total Dollar	81,160,388	96,188,953	(15,028,565)	-15.62%
BTUs Burned	23,637,582	30,484,736	(6,847,154)	-22.46%
\$/mmBtu	3.43	3.16	0.28	8.82%
Generation (MWh)	165,771	2,731,208	(2,565,437)	-93.93%
Fuel Costs (¢ / kWh)	48.96	3.52	45.44	1290.91%
<u>GAS - Generation</u>				
Total Dollar	109,050,227	118,192,873	(9,142,646)	-7.74%
BTUs Burned	40,783,185	45,994,831	(5,211,646)	-11.33%
\$/mmBtu	2.67	2.57	0.10	4.06%
Generation (MWh)	5,420,493	4,668,264	752,229	16.11%
Fuel Costs (¢ / kWh)	2.01	2.53	(0.52)	-20.55%
<u>TOTAL</u>				
Total Dollar	190,254,042	214,438,109	(24,184,067)	-11.28%
BTUs Burned	64,423,638	76,483,174	(12,059,536)	-15.77%
\$/mmBtu	2.95	2.80	0.149	5.33%
Generation (MWh)	7,487,307	8,741,036	(1,253,729)	-14.34%
Fuel Costs (¢ / kWh)	2.54	2.45	0.09	3.67%

Note:

Schedule 3

GULF POWER COMPANY
2020 Natural Gas Hedging Results

	Actual Gas Burn for Generation MMBtu *	Hedged Volume of Gas Burn MMBtu	Gulf Hedge Settlement Cost (\$)
Jan-20	6,450,133	330,000	467,160
Feb-20	6,172,068	330,000	559,890
Mar-20	5,978,078	330,000	578,370
Apr-20			
May-20			
Jun-20			
Jul-20			
Aug-20			
Sep-20			
Oct-20			
Nov-20			
Dec-20			
TOTAL	18,600,279	990,000	\$ 1,605,420
Annual Hedge Ratio:		5%	

* Gas MMBtu burn includes volume for Gulf-owned gas-fired generation and power purchase agreement (PPA) generating units for which Gulf supplies the fuel.

Schedule CCA-1

**GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2020 - DECEMBER 2020**

1. Estimated over/(under)-recovery for the period
January 2020 - December 2020
(Schedule CCE-1E, line 1, filed July 27, 2020 and
approved in FPSC Order No. PSC-2020-0439-FOF-EI
issued on November 16, 2020) \$ (2,700,587)

2. Actual over/(under)-recovery for the period
January 2020 - December 2020
(Schedule CCA-2, Line 10 + 11 + 14) (1,862,460)

3. Amount to be refunded/(recovered) in the
January 2022 - December 2022 projection period
(Line 2 - Line 1) \$ 838,127

Schedule CCA-2

**GULF POWER COMPANY
CAPACITY VARIANCES SUMMARY
ACTUAL vs. ESTIMATED
FOR THE PERIOD
JANUARY 2020 - DECEMBER 2020**

		2020 Final True-Up	2020 Actual/ Estimated	Difference	Percent Variance
1. IIC Payments / (Receipts)	4	(59,084)	9,985	(69,069)	-691.75%
	5				
2. Other Capacity Payments / (Receipts)		84,509,872	85,379,260	(869,388)	-1.02%
3. Transmission Revenue (\$)		(6,538)	(46,235)	39,697	-85.86%
	1-23				
4. Scherer/Flint Credit		2,125	2,125	-	0.00%
5. Total Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) (\$)		84,446,374	85,345,135	(898,761)	-1.05%
6. Jurisdictional %		0.9723427	0.9723427	-	0.00%
7. Total Jurisdictional Recovery Amount (Line 5 * 6) (\$)		82,110,816	82,984,719	(873,903)	-1.05%
8. Jurisdictional Capacity Cost Recovery Revenues Net of Taxes (\$)		80,497,952	80,533,916	(35,964)	-0.04%
9. True-Up Provision (\$)		(237,948)	(237,948)	-	0.00%
10. Jurisdictional Capacity Cost Recovery Revenue (Line 8 + 9) (\$)		80,260,003	80,295,968	(35,965)	-0.04%
11. Over/(Under) Recovery (Line 10 - 7) (\$)		(1,850,813)	(2,688,751)	837,938	-31.16%
12. Interest Provision (\$)		(11,647)	(11,836)	189	-1.60%
13. Beginning Balance True-Up & Interest Provision (\$)		214,896	214,896	-	0.00%
14. True-Up Collected/(Refunded) (\$)		237,948	237,948	-	0.00%
15. Adjustment		-	-	-	0.00%
End of Period Total Net True-Up (Lines 11 + 12 + 13 + 14) (\$)		(1,409,616)	(2,247,743)	838,127	-37.29%

GULF POWER COMPANY

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2020 - DECEMBER 2020

	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	Total
1. IIC Payments / (Receipts) (\$)	23,120	17,509	(3,065)	(3,065)	(3,065)	(3,065)	(3,065)	(1,655)	(1,655)	(12,366)	(1,655)	(68,469)	(59,084)
2. Other Capacity Payments / (Receipts)	7,078,291	7,078,291	7,078,291	7,078,291	7,078,291	7,078,291	7,020,173	7,020,173	7,020,173	7,020,173	7,020,173	6,939,257	84,509,872
3. Transmission Revenue (\$)	(325)	(1,191)	(384)	(387)	(538)	(410)	(372)	(530)	(443)	(600)	(687)	(692)	(6,538)
4. Scherer/Flint Credit	(10)	-	-	2,136	-	-	-	-	-	-	-	-	2,125
5. Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) (\$)	7,101,077	7,094,610	7,074,843	7,076,976	7,074,689	7,074,817	7,018,146	7,017,988	7,018,075	7,007,207	7,017,851	6,870,096	84,446,374
6. Jurisdictional %	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
7. Total Jurisdictional Recovery Amount (Line 4 * 5) (\$)	6,904,680	6,898,392	6,879,171	6,881,246	6,879,022	6,879,147	6,824,043	6,823,889	6,823,974	6,813,407	6,823,757	6,680,088	82,110,816
8. Jurisdictional Capacity Cost Recovery Revenues Net of Taxes (\$)	6,021,267	5,400,394	5,586,050	5,799,020	6,580,082	7,673,878	8,728,542	8,939,693	7,227,503	6,513,444	5,572,842	6,455,236	80,497,952
9. True-Up Provision (\$)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(19,829)	(237,948)
10. Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) (\$)	6,001,438	5,380,565	5,566,221	5,779,191	6,560,253	7,654,049	8,708,713	8,919,864	7,207,674	6,493,615	5,553,013	6,435,407	80,260,003
11. Over/(Under) Recovery (Line 9 - 6) (\$)	(903,242)	(1,517,827)	(1,312,951)	(1,102,055)	(318,769)	774,902	1,884,670	2,095,975	383,700	(319,792)	(1,270,743)	(244,681)	(1,850,813)
12. Interest Provision (\$)	(305)	(1,890)	(4,423)	(3,791)	(273)	(392)	(310)	(110)	16	19	(58)	(130)	(11,647)
13. Beginning Balance True-Up & Interest Provision (\$)	214,896	(668,822)	(2,168,710)	(3,466,255)	(4,552,272)	(4,851,485)	(4,057,146)	(2,152,957)	(37,263)	366,282	66,338	(1,184,634)	214,896
14. True-Up Collected/(Refunded) (\$)	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	19,829	237,948
15. Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
16. End of Period Total Net True-Up (Lines 10 + 11 + 12 + 13 + 14) (\$)	(668,822)	(2,168,710)	(3,466,255)	(4,552,272)	(4,851,485)	(4,057,146)	(2,152,957)	(37,263)	366,282	66,338	(1,184,634)	(1,409,616)	(1,409,616)
Average Monthly Interest Rate	0.1346%	0.1333%	0.1571%	0.0946%	0.0058%	0.0088%	0.0100%	0.0100%	0.0100%	0.0088%	0.0104%	0.0100%	
Wall Street Annual Rate	1.59%	1.64%	1.56%	2.21%	0.06%	0.13%	0.11%	0.13%	0.11%	0.10%	0.15%	0.09%	
Average Annual Rate	1.62%	1.60%	1.89%	1.14%	0.07%	0.11%	0.12%	0.12%	0.12%	0.11%	0.13%	0.12%	

Schedule CCA-4

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2020 - DECEMBER 2020

	Actual JANUARY	Actual FEBRUARY	Actual MARCH	Actual APRIL	Actual MAY	Actual JUNE	Actual JULY	Actual AUGUST	Actual SEPTEMBER	Actual OCTOBER	Actual NOVEMBER	Actual DECEMBER	TOTAL
1. Beginning True-Up Amount (\$)	214,896	(668,822)	(2,168,710)	(3,466,255)	(4,552,272)	(4,851,485)	(4,057,146)	(2,152,957)	(37,263)	366,282	66,338	(1,184,634)	
2. Ending True-Up Amount Before Interest (\$)	(668,517)	(2,166,820)	(3,461,832)	(4,548,481)	(4,851,212)	(4,056,754)	(2,152,647)	(37,153)	366,266	66,319	(1,184,576)	(1,409,486)	
3. Total Beginning & Ending True-Up Amount (\$)(Lines 1 + 2)	(453,621)	(2,835,642)	(5,630,542)	(8,014,736)	(9,403,484)	(8,908,239)	(6,209,793)	(2,190,110)	329,003	432,601	(1,118,238)	(2,594,120)	
4. Average True-Up Amount (\$)	(226,811)	(1,417,821)	(2,815,271)	(4,007,368)	(4,701,742)	(4,454,120)	(3,104,897)	(1,095,055)	164,502	216,301	(559,119)	(1,297,060)	
5. Interest Rate - First Day of Reporting Business Month	1.59%	1.64%	1.56%	2.21%	0.06%	0.08%	0.13%	0.11%	0.13%	0.11%	0.10%	0.15%	
6. Interest Rate - First Day of Subsequent Business Month	1.64%	1.56%	2.21%	0.06%	0.08%	0.13%	0.11%	0.13%	0.11%	0.10%	0.15%	0.09%	
7. Total Interest Rate (Lines 5 + 6)	3.23%	3.20%	3.77%	2.27%	0.14%	0.21%	0.24%	0.24%	0.24%	0.21%	0.25%	0.24%	
8. Average Interest Rate	1.615%	1.600%	1.885%	1.135%	0.070%	0.105%	0.120%	0.120%	0.120%	0.105%	0.125%	0.120%	
9. Monthly Average Interest Rate (1/12 Of Line 8)	0.1346%	0.1333%	0.1571%	0.0946%	0.0058%	0.0088%	0.0100%	0.0100%	0.0100%	0.0088%	0.0104%	0.0100%	
10. Interest Provision For the Month (Lines 4 X 9) (\$)	(305)	(1,890)	(4,423)	(3,791)	(273)	(392)	(310)	(110)	16	19	(58)	(130)	(11,647)

Gulf Power Company
2020 Capacity Contracts

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Contract/Counterparty	Start	Term	End ⁽¹⁾	Contract Type									
1	Southern Intercompany Interchange	5/1/2007	5 Yr Notice		SES Opco									
2	PPAs													
3	Shell Energy N.A. (U.S.), LP	11/2/2009	5/31/2023		Firm									
4	Other													
5	South Carolina PSA	9/1/2003	-		Other									
6	Macquarie	1/1/2020	12/31/2020		Other									
7	REMC Corporation	1/1/2020	2/29/2020		Other									
8														
9	Capacity Costs (\$)	Actual	January ⁽²⁾	Actual	February ⁽²⁾	Actual	March	Actual	April	Actual	May	Actual	June	Actual
10	Southern Intercompany Interchange													
11	PPAs													
12	Shell Energy N.A. (U.S.), LP													
13	Other													
14	South Carolina PSA													
15	Macquarie													
16	REMC Corporation													
17														
18														
	Total	7,101,412		7,095,801		7,075,227		7,075,227		7,018,518		7,018,518		7,018,518
19	Capacity MW													
20	Southern Intercompany Interchange													
21	PPAs													
22	Shell Energy N.A. (U.S.), LP													
23	Other													
24	South Carolina PSA													
25	Macquarie													
26	REMC Corporation													
27														
28														
29														
30														

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.

(2) Southern Intercompany Interchange reserve sharing prior month true up only.



Gulf Power®

January 20, 2021

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

Re: Docket No. 20210001-EI

Dear Mr. Teitzman:

Attached for official filing in the subject docket on behalf of Gulf Power Company are the following for the month of December 2020 based on actual amounts.

- | | | |
|-----|---------------|--|
| 1. | Schedule A1: | Comparison of Estimated and Actual Fuel and Purchased Power Cost Recovery Factor |
| 2. | Schedule A2: | Calculation of True-up and Interest Provision |
| 3. | Schedule A3: | Generating System Comparative Data by Fuel Type |
| 4. | Schedule A4: | System Net Generation and Fuel Cost |
| 5. | Schedule A5: | System Generated Fuel Cost Inventory Analysis |
| 6. | Schedule A6: | Power Sold |
| 7. | Schedule A7: | Purchased Power (Exclusive of Economy Energy Purchases) |
| 8. | Schedule A8: | Energy Payments to Qualifying Facilities |
| 9. | Schedule A9: | Economy Energy Purchases |
| 10. | Schedule A12: | Capacity Contracts |

Pursuant to the Order Establishing Procedure in this docket, electronic copies of the same will be provided to the parties under separate cover.

Sincerely,

A handwritten signature in blue ink that reads "Richard Hume".

Richard Hume
Regulatory Issues Manager

md

Attachment

cc w/attachment: Florida Public Service Commission
Devlin Higgins
Division of Auditing and Safety
Lynn Deamer

Mr. Adam Teitzman, Commission Clerk
Florida Public Service Commission
January 20, 2021
Page 2

bc w/attachment: R. Cain
M. Goldstein
J. Grady
R. Hume
M. Kazadi
L. Roddy
M. Santos
J. Van Norman
A. Whitley

**BEFORE THE FLORIDA PUBLIC
SERVICE COMMISSION**

Docket No. 20200001-EI

MONTHLY FUEL FILING

DECEMBER 2020



SCHEDULE A1a

**GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: DECEMBER 2020**

Line No.	Description	Reference	Amount
1	Fuel Cost of System Net Generation	Schedule A-3	\$ 14,301,975
2	Wholesale kWh Sales Credit	Schedule A-3, Line 2b	\$ (646,631)
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	\$ 52,126
4	Hedging Settlement Costs	Schedule A-2, Line A-5	\$ -
5	Fuel Cost of Purchased Power	Schedule A-7	\$ -
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	\$ 16,366,417
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	\$ -
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 6	\$ 274,033
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7	<u>\$ (3,938,643)</u>
10	Total Fuel and Net Power Transactions		<u><u>\$ 26,409,277</u></u>

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Description	Dollars			KWH			Cents/kWh					
		Actual	Estimated	Difference	Actual	Estimated	Difference	Actual	Estimated	Difference			
1	Fuel Cost of System Net Generation (A3)	14,301,975	18,129,329	(3,827,354)	(21.11)	550,604,300	718,929,000	(168,324,700)	(23.41)	2,5975	2,5217	0.08	3.01
1a	Hedging Settlement Costs (A2)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
1b	Wholesale kWh Sales Credit	(646,631)	0	(646,631)	100.00	(26,414,187)	0	0	100.00	#N/A	0.0000	2.45	0.00
2	Adjustments to Fuel Cost (A2, Page 1) **	52,126	0	52,126	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	TOTAL COST OF GENERATED POWER	13,707,470	18,129,329	(4,421,859)	(24.39)	524,190,113	718,929,000	(168,324,700)	(23.41)	2,6150	2,5217	0.09	3.70
4	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
5	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	16,366,417	16,950,115	(583,698)	(3.44)	574,864,628	592,684,000	(17,819,372)	(3.01)	2,8470	2,8599	(0.01)	(0.45)
6	Energy Payments to Qualifying Facilities (A8)	274,033	0	274,033	100.00	15,828,461	0	15,828,461	100.00	1,7313	0.0000	1.73	0.00
7	TOTAL COST OF PURCHASED POWER	16,640,450	16,950,115	(309,665)	(1.83)	590,693,089	592,684,000	(1,990,911)	(0.34)	2,8171	2,8599	(0.04)	(1.50)
8	Total Available kWh (Line 3 + Line 7)	30,347,920	35,079,444	(4,731,524)	(13.49)	1,114,883,202	1,311,613,000	(196,729,798)	(15.00)	2,7221	2,6745	0.05	1.78
9	Fuel Cost of Economy Sales (A6)	(97,192)	(195,518)	98,326	(50.29)	(4,375,398)	(9,022,000)	4,646,602	(51.50)	(2,2213)	(2,1671)	(0.05)	(2.50)
10	Gain on Economy Sales (A6)	(7,542)	0	(7,542)	100.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Fuel Cost of Other Power Sales (A6)	(3,833,910)	(8,745,754)	4,911,844	(56.16)	(164,640,542)	(414,501,000)	249,860,458	(60.28)	(2,3287)	(2,1099)	(0.22)	(10.37)
12	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 9 + 10 + 11)	(3,938,643)	(8,941,272)	5,002,629	(55.95)	(169,015,940)	(423,523,000)	254,507,060	(60.09)	(2,3303)	(2,1112)	(0.22)	(10.38)
13	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 3 + 7 + 12)	26,409,277	26,138,172	271,105	1.04	945,867,262	888,090,000	57,777,262	6.51	2,7921	2,9432	(0.15)	(5.13)
14	Company Use *	36,290	36,643	(353)	(0.96)	1,299,738	1,245,000	54,738	4.40	2,7921	2,9432	(0.15)	(5.13)
15	T & D Losses *	2,322,380	1,309,901	1,012,479	77.29	83,176,814	44,506,000	38,670,814	86.89	2,7921	2,9432	(0.15)	(5.13)
16	TERRITORIAL KWH SALES	26,409,277	26,138,172	271,105	1.04	861,390,710	842,339,000	19,051,710	2.26	3,0659	3,1030	(0.04)	(1.20)
17	Other Wholesale kWh Sales	(1)	0	(1)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
18	Jurisdictional kWh Sales	26,409,278	26,138,172	271,106	1.04	861,390,710	842,339,000	19,051,710	2.26	3,0659	3,1030	(0.04)	(1.20)
19	Jurisdictional Loss Multiplier	1,0012	1,0012	0	0.00	0	0	0	0.00	1,0012	1,0012	0.00	0.00
20	Jurisdictional kWh Sales Adj. for Line Losses	26,440,968	26,169,538	271,430	1.04	861,390,710	842,339,000	19,051,710	2.26	3,0696	3,1068	(0.04)	(1.20)
21	TRUE-UP	55,569	55,569	0	0.00	861,390,710	842,339,000	19,051,710	2.26	0.0065	0.0066	(0.00)	(1.52)
22	TOTAL JURISDICTIONAL FUEL COST	26,496,537	26,225,107	271,430	1.04	861,390,710	842,339,000	19,051,710	2.26	3,0761	3,1134	(0.04)	(1.20)
23	Revenue Tax Factor									1,00072	1,00072	0.00	0.00
24	Fuel Factor Adjusted for Revenue Taxes									3,0763	3,1156	(0.04)	(1.20)
25	GPWF Reward / (Penalty)	(864)	(864)	0	0.00	861,390,710	842,339,000	19,051,710	2.26	(0.0001)	(0.0001)	0.00	0.00
26	Fuel Factor Adjusted for GPWF Reward / (Penalty) & Tax Savings Credit									3,0782	3,1155	(0.04)	(1.20)
	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.078	3.116		

* Included for Informational Purposes Only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2020
PERIOD TO DATE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Description	Dollars			Difference			KWH			Cents/kWh		
		Actual	Estimated	%	Actual	Estimated	%	Actual	Estimated	Difference	Amount	%	
1	Fuel Cost of System Net Generation (A3)	191,063,661	239,044,372	(47,980,711)	(20.07)	7,963,797,611	9,658,579,000	(1,694,781,389)	(17.55)	2,3992	2,4749	(0.08)	(3.06)
1a	Hedging Settlement Costs (A2)	1,605,420	1,093,590	511,830	46.80	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
2	Wholesale kWh Sales Credit	(5,431,727)	0	(5,431,727)	100.00	(296,814,974)	0	(296,814,974)	100.00	1,8300	0.0000	1.83	0.00
2	Adjustments to Fuel Cost (A2, Page 1) **	(220,797)	0	(220,797)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	TOTAL COST OF GENERATED POWER	187,016,557	240,137,962	(53,121,405)	(22.12)	7,666,982,637	9,658,579,000	(1,991,596,363)	(20.62)	2,4392	2,4863	(0.05)	(1.89)
3	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	172,072,628	193,614,912	(21,542,284)	(11.13)	6,826,394,748	7,386,656,000	(560,261,252)	(7.58)	2,5207	2,6211	(0.10)	(3.83)
5	Energy Payments to Qualifying Facilities (A8)	5,808,964	0	5,808,964	100.00	247,526,454	0	247,526,454	100.00	2,3468	0.0000	2.35	0.00
6	TOTAL COST OF PURCHASED POWER	177,881,592	193,614,912	(15,733,320)	(8.13)	7,073,921,202	7,386,656,000	(312,734,798)	(4.23)	2,5146	2,6211	(0.11)	(4.06)
7	Total Available kWh (Line 3 + Line 7)	364,898,149	433,752,874	(68,854,725)	(15.87)	14,740,903,839	17,045,235,000	(2,304,331,161)	(13.52)	2,4754	2,5447	(0.07)	(2.72)
8	Fuel Cost of Economy Sales (A6)	(1,443,051)	(2,054,358)	611,307	(29.76)	(74,281,875)	(92,292,000)	18,010,125	(19.51)	(1,9427)	(2,2259)	0.28	12.72
9	Gain on Economy Sales (A6)	(202,489)	(58,000)	(144,489)	249.12								
10	Fuel Cost of Other Power Sales (A6)	(54,437,137)	(108,348,313)	53,911,176	(49.76)	(2,991,195,054)	(5,343,805,000)	2,352,609,946	(44.02)	(1,8199)	(2,0275)	0.21	10.24
11	TOTAL FUEL COSTS & GAINS OF POWER SALES												
12	(LINES 9 + 10 + 11)	(56,082,677)	(110,460,671)	54,377,994	(49.23)	(3,065,476,929)	(5,436,097,000)	2,370,620,071	(43.61)	(1,8295)	(2,0320)	0.20	9.97
13	TOTAL FUEL & NET POWER TRANSACTIONS												
14	(LINES 3 + 7 + 12)	308,815,472	323,292,203	(14,476,731)	(4.48)	11,675,426,910	11,609,138,000	66,288,910	0.57	2,6450	2,7848	(0.14)	(5.02)
15	Company Use *	349,992	417,330	(67,338)	(16.14)	13,232,212	14,986,000	(1,753,788)	(11.70)	2,6450	2,7848	(0.14)	(5.02)
16	T & D Losses	17,124,976	15,991,324	1,133,652	7.09	647,447,114	574,236,000	73,211,114	12.75	2,6450	2,7848	(0.14)	(5.02)
17	TERRITORIAL KWH SALES	308,815,471	323,292,203	(14,476,732)	(4.48)	11,014,747,584	11,019,916,000	(5,168,416)	(0.05)	2,8037	2,9337	(0.13)	(4.43)
18	Other Wholesale kWh Sales	(1)	0	(1)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
19	Jurisdictional kWh Sales	308,815,472	323,292,203	(14,476,731)	(4.48)	11,014,747,584	11,019,916,000	(5,168,416)	(0.05)	2,8037	2,9337	(0.13)	(4.43)
20	Jurisdictional Loss Multiplier	1.0012	1.0012	0	0.00					1.0012	1.0012		
21	Jurisdictional kWh Sales Adj. for Line Losses	309,186,051	323,680,153	(14,494,102)	(4.48)	11,014,747,584	11,019,916,000	(5,168,416)	(0.05)	2,8070	2,9372	(0.13)	(4.43)
22	TRUE-UP	666,833	666,833	0	0.00	11,014,747,584	11,019,916,000	(5,168,416)	(0.05)	0.0061	0.0061	0.00	0.00
23	TOTAL JURISDICTIONAL FUEL COST	309,852,884	324,346,986	(14,494,102)	(4.47)	11,014,747,584	11,019,916,000	(5,168,416)	(0.05)	2,8131	2,9433	(0.13)	(4.42)
24	Revenue Tax Factor									1.00072	1.00072		
25	Fuel Factor Adjusted for Revenue Taxes									2.8151	2.9454	(0.13)	(4.42)
26	GPIF Reward / (Penalty)									(0.0001)	(0.0001)	0.00	0.00
27	Fuel Factor Adjusted for GPIF Reward / (Penalty) & Tax Savings Credit									2.8150	2.9453	(0.13)	(4.42)
28	FUEL FACTOR ROUNDED TO NEAREST .001 (CENTS/KWH)												

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A-2
PAGE 1 OF 3

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020

Line No.	Description	CURRENT MONTH			PERIOD-TO-DATE			
		Actual	Estimated	Difference Amount	Actual	Estimated	Difference Amount	
								%
A. Fuel Cost & Net Power Transactions								
1	Fuel Cost of System Net Generation	14,068,144.77	17,876,493	(3,808,348.23)	(21.30)	189,178,390.72	(47,403,586.28)	(20.04)
1a	Other Generation	233,830.35	252,836	(19,005.65)	(7.52)	1,885,270.56	(577,125.44)	(23.44)
1b	Wholesale kWh Sales Credit	(646,631.07)	0	(646,631.07)	100.00	(5,431,726.91)	0	(5,431,726.91)
2	Fuel Cost of Power Sold	(3,938,642.99)	(8,941,272)	5,002,629.01	55.95	(56,082,676.82)	(110,460,671)	54,377,994.18
3	Fuel Cost - Purchased Power	16,366,417.10	16,950,115	(583,697.90)	(3.44)	172,072,627.81	193,614,911	(21,542,283.19)
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00
3b	Energy Payments to Qualifying Facilities	274,032.85	0	274,032.85	100.00	5,808,964.09	0	5,808,964.09
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00
5	Hedging Settlement Cost	0.00	0	0.00	0.00	1,605,420.00	1,093,590	511,830.00
6	Total Fuel & Net Power Transactions	26,357,151.01	26,138,172	218,979.01	0.84	309,036,269.45	323,292,203	(14,255,933.55)
7	AdjustmentsTo Fuel Cost*	52,125.58	0.00	52,125.58	100.00	(220,797.15)	0	(220,797.15)
8	Adj. Total Fuel & Net Power Transactions	26,409,276.59	26,138,172	271,104.59	1.04	308,815,472.30	323,292,203	(14,476,730.70)
B. KWH Sales								
1	Jurisdictional Sales	834,976.523	842,339,000	(7,362,477)	(0.87)	10,717,932,610	11,019,916,000	(301,983,390)
2	Non-Jurisdictional Sales	26,414,187	0	26,414,187	100.00	296,814,974	0	296,814,974
3	Total Territorial Sales	861,390,710	842,339,000	19,051,710	2.26	11,014,747,584	11,019,916,000	(5,168,416)
4	Juris. Sales as % of Total Terr. Sales	100.0000	100.0000	0.0000	0.00	100.0000	100.0000	0.0000

0.00

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SCHEDULE A-2
PAGE 2 OF 3

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020

Line No.	Description	CURRENT MONTH			PERIOD-TO-DATE				
		Actual	Estimated	Difference Amount	Actual	Estimated	Difference Amount		
C. True-up Calculation									
1	Jurisdictional Fuel Revenue	25,830,093.98	27,305,817	(1,475,722.99)	(5.40)	305,319,719.38	(51,909,150.87)	(14.53)	
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(55,569.00)	(55,569)	0.00	0.00	(666,833.00)	(666,833)	0.00	
2b	Incentive Provision	(864)	(864)	0.00	0.00	(10,377)	(10,377)	0.00	
3	Juris. Fuel Revenue Applicable to Period	25,773,660.98	27,249,384	(1,475,723.02)	(5.42)	304,642,509.38	356,551,660	(51,909,150.62)	
	Adjusted Total Fuel & Net Power								
4	Transactions (Line A8)	26,409,276.59	26,138,172	271,104.59	1.04	308,815,472.30	323,292,203	(14,476,730.70)	(4.48)
5	Juris. Sales % of Total KWH Sales (Line B4)	100.0000	100.0000	0.0000	0.00	97.3053	100.0000	(2.6947)	(2.69)
	Juris. Total Fuel & Net Power Transactions								
6	Adj. for Line Losses (C4*C5*1.0012)	26,440,967.72	26,169,538	271,429.72	1.04	309,186,050.87	323,680,153	(14,494,102.13)	(4.48)
	True-Up Provision for the Month								
7	Over/(Under) Collection (C3-C6)	(667,306.74)	1,079,846	(1,747,152.74)	161.80	(4,543,541.49)	32,871,507	(37,415,048.49)	113.82
8	Interest Provision for the Month	529.13	3,231	(2,701.87)	83.62	39,933.20	7,319	32,614.20	(445.61)
9	Beginning True-Up & Interest Provision	5,597,198.56	31,740,180	(26,142,981.44)	82.37	8,201,762.06	(666,833)	8,968,595.06	1,329.96
10	True-Up Collected / (Refunded)	55,569.00	55,569	0.00	0.00	666,833.00	666,833	0.00	0.00
	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	4,985,989.95	32,878,826	(27,892,836.05)	84.84	4,364,986.77	32,878,826	(28,513,839.23)	86.72
12	Adjustment	0.00	0	0.00	0.00	621,002.82	0	621,002.82	100.00
13	End of Period - Total Net True-Up	4,985,989.95	32,878,826	(27,892,836.05)	84.84	4,985,989.59	32,878,826	(27,892,836.41)	84.84

**CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020**

Line No.	Description	CURRENT MONTH			
		Actual	Estimated	Difference	
				Amount	%
D. Interest Provision					
1	Beginning True-Up Amount (C9)	5,597,198.56	31,740,180	(26,142,981.44)	(82.37)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	4,985,460.82	32,875,595	(27,890,134.18)	(84.84)
3	Total of Beginning & Ending True-Up Amts.	10,582,659.38	64,615,775	(54,033,115.62)	(83.62)
4	Average True-Up Amount	5,291,329.69	32,307,888	(27,016,558.31)	(83.62)
	Interest Rate				
5	1st Day of Reporting Business Month	0.15	0.15	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.09	0.09	0.0000	
7	Total (D5+D6)	0.24	0.24	0.0000	
8	Annual Average Interest Rate	0.12	0.12	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.01	0.01	0.0000	
10	Interest Provision (D4*D9)	529.13	3,231	(2,701.87)	(83.62)
	Jurisdictional Loss Multiplier	1.0012	1.0012		

SCHEDULE A-3
Revised 2.22.2021

**GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020**

Line No.	Description	CURRENT MONTH				PERIOD-TO-DATE			
		Actual	Estimated	Difference		Actual	Estimated	Difference	
				Amount	%			Amount	%
<u>FUEL COST-NET GEN.(\$)</u>									
1	LIGHTER OIL (B.L.)	55,796	48,245	7,551	15.65	608,658	539,831	68,827	12.75
2	COAL	5,462,011	3,765,240	1,696,771	45.06	73,030,501	90,299,232	(17,268,731)	(19.12)
2a	Coal at Scherer	734,889	1,429,790	(694,901)	(48.60)	7,316,675	19,345,227	(12,028,552)	(62.18)
3	GAS	7,999,347	12,804,382	(4,805,035)	(37.53)	109,050,227	125,803,631	(16,753,404)	(13.32)
4	GAS (B.L.)	-	0	0	0.00	204,554	2,106,458	(1,901,904)	(90.29)
5	LANDFILL GAS	49,933	81,672	(31,739)	(38.86)	809,620	921,889	(112,269)	(12.18)
6	OIL - C.T.	0	0	0	0.00	43,427	28,104	15,323	54.52
7	TOTAL (\$)	<u>14,301,975</u>	<u>18,129,329</u>	<u>(3,827,354)</u>	<u>(21.11)</u>	<u>191,063,661</u>	<u>239,044,372</u>	<u>(47,980,711)</u>	<u>(20.07)</u>
<u>SYSTEM NET GEN. (MWH)</u>									
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	142,323	139,322	3,001	2.15	1,849,005	2,764,652	(915,647)	(33.12)
9a	Coal at Scherer	23,448	49,923	(26,475)	(53.03)	217,732	680,210	(462,478)	(67.99)
10	GAS	346,472	517,687	(171,215)	(33.07)	5,420,493	5,997,300	(576,807)	(9.62)
11	LANDFILL GAS	1,216	2,097	(881)	(42.01)	21,615	24,765	(3,150)	(12.72)
12	OIL - C.T.	29	0	29	100.00	77	552	(475)	(86.05)
13	SOLAR	10,702	9,900	802	8.10	158,061	191,100	(33,039)	(17.29)
14	TOTAL (MWH)	<u>524,190</u>	<u>718,929</u>	<u>(194,739)</u>	<u>(27.09)</u>	<u>7,666,983</u>	<u>9,658,579</u>	<u>(1,991,596)</u>	<u>(20.62)</u>
<u>UNITS OF FUEL BURNED</u>									
15	LIGHTER OIL (BBL)	821	830	(9)	(1.08)	7,985	7,713	272	3.53
16	COAL (TONS)	209,243	76,064	133,179	175.09	1,228,157	1,445,315	(217,158)	(15.02)
17	GAS (MCF) (1)	2,632,715	4,108,460	(1,475,745)	(35.92)	39,742,673	45,730,694	(5,988,021)	(13.09)
18	OIL - C.T. (BBL)	17	0	17	100.00	494	308	186	60.48
<u>BTU'S BURNED (MMBTU)</u>									
19	COAL + GAS B.L. + OIL B.L.	1,612,897	1,917,497	(304,600)	(15.89)	23,637,582	32,660,131	(9,022,549)	(27.63)
20	GAS - Generation (1)	2,705,871	4,108,460	(1,402,589)	(34.14)	40,783,185	39,945,792	837,393	2.10
21	OIL - C.T.	99	0	99	100.00	2,871	1,800	1,071	59.50
22	TOTAL (MMBTU)	<u>4,318,867</u>	<u>6,025,957</u>	<u>(1,707,090)</u>	<u>(28.33)</u>	<u>64,423,638</u>	<u>72,607,723</u>	<u>(8,184,085)</u>	<u>(11.27)</u>
<u>GENERATION MIX (% MWH)</u>									
23	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	COAL	31.62	26.32	5.30	20.14	26.96	35.66	(8.70)	(24.40)
25	GAS	66.10	72.01	(5.91)	(8.21)	70.70	62.09	8.61	13.87
26	LANDFILL GAS	0.23	0.29	(0.06)	(20.69)	0.28	0.26	0.02	7.69
27	OIL - C.T.	0.01	0.00	0.01	100.00	0.00	0.01	(0.01)	(100.00)
28	SOLAR	2.04	1.38	0.66	47.83	2.06	1.98	0.08	4.04
29	TOTAL (% MWH)	<u>100.00</u>	<u>100.00</u>	<u>0.00</u>	<u>0.00</u>	<u>100.00</u>	<u>100.00</u>	<u>0.00</u>	<u>0.00</u>
<u>FUEL COST (\$ / UNIT)</u>									
30	LIGHTER OIL (\$/BBL)	67.96	58.14	9.82	16.89	76.23	69.99	6.24	8.92
31	COAL (\$/TON) (2)	26.10	49.50	(23.40)	(47.27)	59.46	62.48	(3.02)	(4.83)
32	GAS (\$/MCF) (1)	2.95	3.06	(0.11)	(3.59)	2.70	2.74	(0.04)	(1.46)
33	OIL - C.T. (\$/BBL)	0.00	0.00	0.00	0.00	87.91	91.39	(3.48)	(3.81)
<u>FUEL COST (\$ / MMBTU)</u>									
34	COAL + GAS B.L. + OIL B.L. (2)	3.88	2.73	1.15	42.12	3.43	3.44	(0.01)	(0.29)
35	GAS - Generation (1)	2.87	3.06	(0.19)	(6.21)	2.63	3.09	(0.46)	(14.89)
36	OIL - C.T.	0.00	0.00	0.00	0.00	15.13	15.61	(0.48)	(3.07)
37	TOTAL (\$/MMBTU)	<u>3.25</u>	<u>2.95</u>	<u>0.30</u>	<u>10.17</u>	<u>2.92</u>	<u>3.25</u>	<u>(0.33)</u>	<u>(10.15)</u>
<u>BTU BURNED / KWH</u>									
38	COAL + GAS B.L. + OIL B.L.	9,730	10,132	(402)	(3.97)	11,437	9,481	1,956	20.63
39	GAS - Generation (1)	8,004	8,087	(83)	(1.03)	7,622	6,763	859	12.70
40	OIL - C.T.	3,414	0	3,414	100.00	37,286	3,261	34,025	1,043.39
41	TOTAL (BTU/KWH)	<u>8,394</u>	<u>8,521</u>	<u>(127)</u>	<u>(1.49)</u>	<u>8,504</u>	<u>7,608</u>	<u>896</u>	<u>11.78</u>
<u>FUEL COST (¢ / KWH)</u>									
42	COAL + GAS B.L. + OIL B.L. (2)	3.77	2.77	1.00	36.10	3.93	3.26	0.67	20.55
43	GAS	2.31	2.47	(0.16)	(6.48)	2.01	2.10	(0.09)	(4.29)
44	LANDFILL GAS	4.11	3.89	0.22	5.66	3.75	3.72	0.03	0.81
45	OIL - C.T.	0.00	0.00	0.00	0.00	56.40	5.09	51.31	1,008.06
46	TOTAL (¢/KWH)	<u>2.73</u>	<u>2.52</u>	<u>0.21</u>	<u>8.33</u>	<u>2.49</u>	<u>2.47</u>	<u>0.02</u>	<u>0.81</u>

Note: (1) Calculations for Line 17, 20, 31, 34, and 38 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

(2) Coal adjustment related to Crist coal buyout expenses.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020

(1) Line No.	(2) Plant/Unit & Fuel Type	(3) Net Cap. (MW)	(4) Net Gen. (MWh)	(5) Cap. Factor (%)	(6) Equiv. Avail. Factor (%)	(7) Net Output Factor (%)	(8) Avg. Net Heat Rate (Btu/kWh)	(9) Fuel Burned Units (Tons/MCF/Bbl)	(10) Fuel Heat Value (lbs./cf/Gal.)	(11) Fuel Burned (MMBtu)	(12) Fuel Burned Cost (\$)	(13) Fuel Cost/kWh (\$/kWh)	(14) Fuel Cost/Unit (\$/Unit)
1	Crist 4	75	0	5.0	83.9	51.4	19,857						
2	Coal	0	0					0	0	0	0	0.00	0.00
3	Gas-G	2,774						53,551	0	55,084	134,075	4.83	2.43
4	Gas-S							0	0	0	0	0.00	0.00
5	Oil-S							0	0	0	0	0.00	0.00
6	Crist 5	75	(575)	0.0	0.0	0.0	N/A						
7	Coal	0	0					0	0	0	0	0.00	0.00
8	Gas-G	0						0	0	0	0	0.00	0.00
9	Gas-S							0	0	0	0	0.00	0.00
10	Oil-S							0	0	0	0	0.00	0.00
11	Crist 6	299	0	7.9	30.3	28.6	11,361						
12	Coal	0	0					0	0	0	0	0.00	0.00
13	Gas-G	17,555						193,883	0	199,434	485,426	2.77	2.50
14	Gas-S	0						0	0	0	0	0.00	0.00
15	Oil-S							7	0	0	360	51.43	51.43
16	Crist 7	475	(92)	0.0	0.0	0.0	N/A						
17	Coal	0	0					0	0	0	0	0.00	0.00
18	Gas-G	0						0	0	0	0	0.00	0.00
19	Gas-S							0	0	0	0	0.00	0.00
20	Oil-S							0	0	0	0	0.00	0.00
21	Smith 3	664	318,384	64.4	71.4	88.9	7,699	2,385,281	1,028	2,451,353	7,146,016	2.24	3.00
22	Gas-G												
23	Smith A ⁽¹⁾	32	29	0.1	100.0	114.3	3,407	17	138,388	99	0	0.00	0.00
24	Oil												
25	Scherer 3 ⁽²⁾	215	23,448	14.7	67.7	32.5	3,458	333	0	81,080	734,889	3.13	9.06
26	Coal								138,500	1,937	25,404	0.00	76.29
27	Oil												
28	Other Generation		8,426								233,830	2.77	0.00
29	Gas												
30	Perdido		1,216								49,833	4.11	0.00
31	Landfill Gas		10,702										
32	Blue Indigo												
33	Solar										0		
34	Daniel 1 ⁽³⁾	251	59,779	32.0	62.3	49.8	11,047	38,158	8,654	660,401	1,913,259	3.20	50.14
35	Coal							413	138,184	2,399	25,814		62.50
36	Oil-S												
37	Daniel 2 ⁽³⁾	251	82,544	44.2	84.7	57.0	10,500	49,600	8,654	866,688	2,486,990	3.01	50.14
38	Coal							68	138,184	392	4,218		62.03
39	Oil-S												
40	Total	2,337	524,190	30.1	50.2	46.6	8,394			4,318,867	13,240,214	2.53	

Notes & Adjustments:	Adj. Units	Adj Description	Adj \$	cents/kWh
(1) Smith A uses lighter oil	N/A	Daniel Railcar Track Deprec.	(6,994.55)	
(2) Represents Gulf's 25% ownership	121,485	Crist Coal Adjustment	1,068,756	
(3) Represents Gulf's 50% ownership				
Negative Net Generation at any unit is due to station service				
Gas-G is gas used for generation. Gas-S is gas used for starter				

Recoverable Fuel 14,301,976 2.73

SCHEDULE A-5
PAGE 1 OF 2

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020

Line No.	Description	CURRENT MONTH				PERIOD-TO-DATE			
		Actual	Estimated	Difference		Actual	Estimated	Difference	
				Amount	%			Amount	%
<u>LIGHT OIL</u>									
1	PURCHASES :								
2	UNITS (BBL)	982	825	157	19.03	10,350	10,391	(41)	(0.39)
3	UNIT COST (\$/BBL)	66.78	53.44	13.34	24.96	60.57	65.60	(5.03)	(7.67)
4	AMOUNT (\$)	65,579	44,086	21,493	48.75	626,862	681,626	(54,764)	(8.03)
5	BURNED :								
6	UNITS (BBL)	828	830	(2)	(0.24)	8,064	10,716	(2,652)	(24.75)
7	UNIT COST (\$/BBL)	68.07	58.14	9.93	17.08	78.57	75.31	3.26	4.33
8	AMOUNT (\$)	56,361	48,245	8,116	16.82	633,585	807,104	(173,519)	(21.50)
9	ENDING INVENTORY :								
10	UNITS (BBL)	7,716	7,652	64	0.84	7,716	7,652	64	0.84
11	UNIT COST (\$/BBL)	60.49	56.35	4.14	7.35	60.49	56.35	4.14	7.35
12	AMOUNT (\$)	466,707	431,204	35,503	8.23	466,707	431,204	35,503	8.23
13	DAYS SUPPLY	N/A	N/A						
<u>COAL EXCLUDING PLANT SCHERER</u>									
14	PURCHASES :								
15	UNITS (TONS)	79,666	72,000	7,666	10.65	990,191	1,442,689	(452,498)	(31.36)
16	UNIT COST (\$/TON)	58.33	47.34	10.99	23.22	60.65	55.77	4.88	8.75
17	AMOUNT (\$)	4,646,840	3,408,582	1,238,258	36.33	60,053,049	80,454,212	(20,401,163)	(25.36)
18	BURNED :								
19	UNITS (TONS)	209,243	76,064	133,179	175.09	1,228,157	1,570,859	(342,702)	(21.82)
20	UNIT COST (\$/TON)	74.03	49.50	24.53	49.56	61.47	63.20	(1.73)	(2.74)
21	AMOUNT (\$)	15,490,773	3,765,240	11,725,533	311.42	75,490,197	99,282,771	(23,792,574)	(23.96)
22	ENDING INVENTORY :								
23	UNITS (TONS)	283,252	267,145	16,107	6.03	283,252	267,145	16,107	6.03
24	UNIT COST (\$/TON)	50.14	18.05	32.09	177.78	50.14	18.05	32.09	177.78
25	AMOUNT (\$)	14,202,168	4,822,639	9,379,529	194.49	14,202,168	4,822,639	9,379,529	194.49
26	DAYS SUPPLY	18	17						
<u>COAL AT PLANT SCHERER</u>									
27	PURCHASES :								
28	UNITS (MMBTU)	202,023	687,562	(485,539)	(70.62)	3,029,524	9,432,246	(6,402,722)	(67.88)
29	UNIT COST (\$/MMBTU)	5.26	2.68	2.58	96.27	3.12	2.63	0.49	18.63
30	AMOUNT (\$)	1,063,592	1,839,239	(775,647)	(42.17)	9,461,870	24,808,105	(15,346,235)	(61.86)
31	BURNED :								
32	UNITS (MMBTU)	81,080	535,461	(454,381)	(84.86)	2,490,908	10,136,350	(7,645,442)	(75.43)
33	UNIT COST (\$/MMBTU)	9.06	2.67	6.39	239.33	3.05	2.34	0.71	30.34
34	AMOUNT (\$)	734,889	1,429,790	(694,901)	(48.60)	7,586,831	23,724,868	(16,138,037)	(68.02)
35	ENDING INVENTORY :								
36	UNITS (MMBTU)	3,704,781	4,031,430	(326,649)	(8.10)	3,704,781	4,031,430	(326,649)	(8.10)
37	UNIT COST (\$/MMBTU)	2.79	2.81	(0.02)	(0.71)	2.79	2.81	(0.02)	(0.71)
38	AMOUNT (\$)	10,321,233	11,339,619	(1,018,386)	(8.98)	10,321,233	11,339,619	(1,018,386)	(8.98)
39	DAYS SUPPLY	69	75						

SCHEDULE A-5
PAGE 2 OF 2

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020

Line No.	Description	CURRENT MONTH				PERIOD-TO-DATE			
		Actual	Estimated	Difference		Actual	Estimated	Difference	
				Amount	%			Amount	%
	<u>GAS</u>	(Reported on a MMBTU and \$ basis)							
40	PURCHASES :								
41	UNITS (MMBTU)	2,705,871	4,108,460	(1,402,589)	(34.14)	42,718,917	44,447,826	(1,728,909)	(3.89)
42	UNIT COST (\$/MMBTU)	2.92	3.06	(0.14)	(4.58)	2.61	2.93	(0.32)	(10.92)
43	AMOUNT (\$)	7,887,967	12,551,546	(4,663,579)	(37.16)	111,665,731	130,048,521	(18,382,790)	(14.14)
44	BURNED :								
45	UNITS (MMBTU)	2,705,871	4,108,460	(1,402,589)	(34.14)	40,783,185	44,447,826	(3,664,641)	(8.24)
46	UNIT COST (\$/MMBTU)	2.92	3.06	(0.14)	(4.58)	2.64	2.93	(0.29)	(9.90)
47	AMOUNT (\$)	7,887,967	12,551,546	(4,663,579)	(37.16)	107,491,961	130,048,521	(22,556,560)	(17.34)
48	ENDING INVENTORY :								
48	UNITS (MMBTU)	495,230	0	495,230	100.00	495,230	0	495,230	100.00
50	UNIT COST (\$/MMBTU)	2.58	0.00	2.58	100.00	2.58	0.00	2.58	100.00
51	AMOUNT (\$)	1,277,432	0	1,277,432	100.00	1,277,432	0	1,277,432	100.00
	<u>OTHER - C.T. OIL</u>								
52	PURCHASES :								
53	UNITS (BBL) *	791	0	791	100.00	1,456	0	1,456	100.00
54	UNIT COST (\$/BBL)	58.86	0.00	58.86	100.00	68.66	0.00	69.00	100.00
55	AMOUNT (\$)	46,558	0	46,558	100.00	99,969	0	99,969	100.00
56	BURNED :								
57	UNITS (BBL)	17	0	17	100.00	494	308	186	60.48
58	UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	88.19	91.39	(3.20)	(3.50)
59	AMOUNT (\$)	0	0	0	0.00	43,567	28,104	15,463	55.02
60	ENDING INVENTORY :								
61	UNITS (BBL)	7,587	6,572	1,015	15.44	7,587	6,572	1,015	15.44
62	UNIT COST (\$/BBL)	87.58	92.06	(4.48)	(4.87)	87.58	92.06	(4.48)	(4.87)
63	AMOUNT (\$)	664,469	605,056	59,413	9.82	664,469	605,056	59,413	9.82
64	HOURS SUPPLY	86	74						

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020

CURRENT MONTH

Line No.	Sold To	Type and Schedule	Total KWH Sold	KWH Wheeled from Other Systems	KWH from Own Generation	¢ / kWh		Total \$ for Fuel Adjustment	Total Cost (\$)
						Fuel Costs	Total Costs		
ESTIMATED									
1	Southern Company Interchange		414,501,000	0	414,501,000	2.11	2.58	8,745,754	10,677,258
2	Various	Economy Sales	9,022,000	0	9,022,000	2.17	2.57	195,518	231,947
3		Gain on Econ. Sales	0	0	0	0.00	0.00	0	0
4	TOTAL ESTIMATED SALES		423,523,000	0	423,523,000	2.11	2.58	8,941,272	10,909,205
ACTUAL									
5	Southern Company Interchange		169,015,940	0	169,015,940	2.32	2.50	3,929,528	4,223,781
6	A.E.C.	External	153,857	0	153,857	2.45	3.25	3,774	5,002
7	DUKE PWR	External	181,434	0	181,434	2.08	3.16	3,774	5,730
8	EAGLE EN	External	565,336	0	565,336	2.22	2.94	12,577	16,603
9	ENDURE	External	0	0	0	0.00	0.00	0	0
10	EXELON	External	142,638	0	142,638	2.57	3.05	3,665	4,354
11	FPC	External	72,021	0	72,021	3.01	3.88	2,168	2,795
12	FPL	External	0	0	0	0.00	0.00	0	0
13	MACQUARI	External	284,774	0	284,774	2.67	3.30	7,595	9,411
14	MERCURIA	External	29,424	0	29,424	3.03	3.10	893	912
15	MISO	External	1,179,140	0	1,179,140	1.99	2.44	23,451	28,713
16	MORGAN	External	30,036	0	30,036	2.44	3.20	732	961
17	NCEMC	External	0	0	0	0.00	0.00	0	0
18	NTE	External	0	0	0	0.00	0.00	0	0
19	OPC	External	67,425	0	67,425	2.25	2.87	1,520	1,934
20	ORLANDO	External	0	0	0	0.00	0.00	0	0
21	PJM	External	345,404	0	345,404	2.36	2.84	8,155	9,796
22	REMC	External	24,520	0	24,520	2.38	3.10	585	760
23	SCE&G	External	96,055	0	96,055	2.50	3.20	2,400	3,076
24	SEPA	External	0	0	0	0.00	0.00	0	0
25	TAL	External	52,105	0	52,105	1.81	3.40	942	1,771
26	TEA	External	1,007,178	0	1,007,178	2.13	2.83	21,494	28,550
27	TECO	External	15,325	0	15,325	2.78	4.22	427	647
28	TVA	External	67,426	0	67,426	2.54	3.25	1,709	2,194
29	WRI	External	61,300	0	61,300	2.17	3.30	1,332	2,023
30	Less: Flow-Thru Energy		(4,375,398)	0	(4,375,398)	2.19	2.19	(95,618)	(95,618)
31	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	7,542	7,542
32	TOTAL ACTUAL SALES		169,015,940	0	169,015,940	2.33	2.52	3,938,643	4,253,394
33	Difference in Amount		(254,507,060)	0	(254,507,060)	0.22	0.00	(5,002,629)	(6,655,811)
34	Difference in Percent		(60.09)	0	(60.09)	10.43	0.00	(55.95)	(61.01)

Note: (1) Gains in the Total Cost column are included in the total cost for each counterparty, but shown separately on line 31 for informational purposes.

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020

PERIOD TO DATE

Line No.	Sold To	Type and Schedule	Total KWH Sold	Kwh Wheeled from Other Systems	KWH from Own Generation	¢ / kWh		Total \$ for Fuel Adjustment	Total Cost (\$)
						Fuel Costs	Total Costs		
ESTIMATED									
1	Southern Company Interchange		5,343,805,000	0	5,343,805,000	2.03	2.40	108,348,313	127,992,156
2	Various Economy Sales		92,292,000	0	92,292,000	2.23	2.56	2,054,358	2,364,506
3	Gain on Econ. Sales		0	0	0	0.00	0.00	58,000	58,000
4	TOTAL ESTIMATED SALES		5,436,097,000	0	5,436,097,000	2.03	2.40	110,460,671	130,414,662
ACTUAL									
5	Southern Company Interchange		3,065,476,929	0	3,065,476,929	1.82	2.04	55,832,075	62,451,441
6	A.E.C.	External	3,525,698	0	3,525,698	2.05	2.69	72,275	94,938
7	DUKE PWR	External	1,076,554	0	1,076,554	2.10	3.64	22,615	39,142
8	EAGLE EN	External	5,352,220	0	5,352,220	1.91	2.58	102,091	138,074
9	ENDURE	External	153,298	0	153,298	1.87	3.29	2,861	5,046
10	EXELON	External	5,394,694	0	5,394,694	1.66	2.12	89,652	114,173
11	FPC	External	2,577,394	0	2,577,394	2.00	3.23	51,508	83,360
12	FPL	External	1,635,559	0	1,635,559	2.15	3.54	35,128	57,911
13	MACQUARI	External	2,041,452	0	2,041,452	3.20	2.80	65,379	57,207
14	MERCURIA	External	2,689,319	0	2,689,319	1.91	2.40	51,437	64,517
15	MISO	External	14,409,903	0	14,409,903	1.57	2.11	226,830	304,315
16	MORGAN	External	1,298,036	0	1,298,036	3.25	3.00	42,170	38,998
17	NCEMC	External	46,894	0	46,894	1.61	1.89	756	888
18	NTE	External	149,572	0	149,572	1.41	1.88	2,111	2,810
19	OPC	External	1,547,434	0	1,547,434	1.82	2.76	28,139	42,667
20	ORLANDO	External	585,807	0	585,807	2.53	3.56	14,830	20,835
20	PJM	External	2,641,956	0	2,641,956	2.13	3.10	56,316	81,847
21	REMC	External	1,764,692	0	1,764,692	1.86	2.47	32,753	43,522
22	SCE&G	External	570,636	0	570,636	2.32	3.46	13,247	19,771
23	SEPA	External	1,841,179	0	1,841,179	1.52	2.10	28,064	38,756
24	TAL	External	220,967	0	220,967	2.23	3.67	4,931	8,115
25	TEA	External	18,585,267	0	18,585,267	1.94	2.80	361,159	520,507
26	TECO	External	805,981	0	805,981	2.35	4.13	18,956	33,288
27	TVA	External	4,316,524	0	4,316,524	2.29	3.60	98,790	155,236
28	WRI	External	1,050,839	0	1,050,839	2.00	2.98	21,054	31,352
29	Less: Flow-Thru Energy		(74,281,875)	0	(74,281,875)	1.88	1.88	(1,394,938)	(1,394,938)
30	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	202,489	202,489
31	TOTAL ACTUAL SALES		3,065,476,929	0	3,065,476,929	1.83	2.06	56,082,676	63,053,776
32	Difference in Amount		(2,370,620,071)	0	(2,370,620,071)	(0.20)	(0.34)	(54,377,995)	(67,360,886)
33	Difference in Percent		(43.61)	0	(43.61)	(9.85)	(14.17)	(49.23)	(51.65)

Note: (1) Gains in the Total Cost column are included in the total cost for each counterparty, but shown separately on line 30 for informational purposes.

SCHEDULE A-7

**PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: DECEMBER 2020**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Month	Purchased From	Type & Schedule	Total KWH Purchased	KWH for Other Utilities	KWH for Interruptible	KWH for Firm	Fuel Cost	¢ / kWh Total Cost	Total \$ for Fuel Adj

1 ESTIMATED:

2 NONE

3 ACTUAL:

4 NONE

SCHEDULE A-8

**ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2020**

CURRENT MONTH

Line No.	Purchased From	Type & Schedule	Total KWH Purchased	KWH for Other Utilities	KWH for Interruptible	KWH for Firm	¢ / kWh		Total \$ for Fuel Adj
							Fuel Cost	Total Cost	
ACTUAL									
1	Bay County/Engen, LLC	Contract	5,000,000	0	0	0	3.11	3.11	155,710
2	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	20,587
3	Ascend Performance Materials	COG 1	10,715,000	0	0	0	0.88	0.88	94,568
4	International Paper	COG 1	113,461	0	0	0	2.79	2.79	3,168
5	TOTAL		15,828,461	0	0	0	1.73	1.73	274,033

PERIOD-TO-DATE

Line No.	Purchased From	Type & Schedule	Total KWH Purchased	KWH for Other Utilities	KWH for Interruptible	KWH for Firm	¢ / kWh		Total \$ for Fuel Adj
							Fuel Cost	Total Cost	
ACTUAL									
6	Bay County/Engen, LLC	Contract	51,683,000	0	0	0	3.11	3.11	1,609,334
7	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	23,086
8	Ascend Performance Materials	COG 1	195,039,980	0	0	0	2.13	2.13	4,157,051
9	International Paper	COG 1	803,474	0	0	0	2.43	2.43	19,494
10	TOTAL		247,526,454	0	0	0	2.35	2.35	5,808,964

SCHEDULE A-9

ECONOMY ENERGY PURCHASES INCLUDING LONG TERM PURCHASES GULF POWER COMPANY FOR THE MONTH OF: DECEMBER 2020

		CURRENT MONTH			PERIOD - TO - DATE		
Line No.	Purchased From	Total KWH Purchased	Trans. Costs ¢ / KWH	Total \$ for Fuel Adj	Total KWH Purchased	Trans. Costs ¢ / KWH	Total \$ for Fuel Adj
<u>ESTIMATED</u>							
1	Southern Company Interchange	60,758,000	2.14	1,302,979	307,510,000	2.29	7,039,076
2	Economy Energy	2,420,000	2.61	63,136	45,691,000	2.53	1,155,836
3	Other Purchases	529,506,000	2.94	15,584,000	7,033,455,000	2.64	185,420,000
4	TOTAL ESTIMATED PURCHASES	592,684,000	2.86	16,950,115	7,386,656,000	2.62	193,614,912
<u>ACTUAL</u>							
5	Southern Company Interchange	76,592,696	1.11	848,512	394,611,596	1.95	7,714,228
6	Non-Associated Companies	3,822,375	3.79	144,891	160,890,661	2.20	3,546,258
7	Purchased Power Agreements	407,543,000	2.82	11,506,857	5,053,308,000	2.11	106,865,826
8	Renewable Energy Purchase Agreements	91,173,118	4.34	3,958,509	1,264,652,133	4.37	55,265,797
9	Other Wheeled Energy	45,537	N/A	N/A	26,397,633	N/A	N/A
10	Other Transactions	63,300	N/A	11,919	816,600	N/A	235,286
11	Less: Flow-Thru Energy	(4,375,398)	2.38	(104,272)	(74,281,875)	2.09	(1,554,767)
12	TOTAL ACTUAL PURCHASES	574,864,628	2.85	16,366,417	6,826,394,748	2.52	172,072,628
13	Difference in Amount	(17,819,372)	(0.01)	(583,698)	(560,261,252)	(0.10)	(21,542,284)
14	Difference in Percent	(3.01)	(0.35)	(3.44)	(7.58)	(3.82)	(11.13)

Capacity Costs (\$)

Capacity Costs (MW)

[illegible]

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Schedule Acronym
Definitions Page 1 of 2

Acronym	Definition
MWH	Megawatt Hour
KWH	Kilowatt Hour
T&D	Transmission & Distribution
Adj.	Adjusted
GPIF	Generating Performance Incentive Factor
Terr.	Territorial
Adj. Revs.	Adjusted Revenues
Juris.	Jurisdictional
B.L.	Boiler Lighter
BBL	Oil Barrel
C.T.	Combustion Turbine
cf	Cubic feet
MCF	Thousand cubic feet
BTU	British Thermal Unit
MMBTU	Million British Thermal Units
lbs.	Pounds
Gal.	Gallons
Deprec.	Depreciation
Econ.	Economy
COG	Cogeneration
Co-op	Cooperative

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Schedule Acronym Definitions
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A-6 Counterparties

Party	Name
AEC	PowerSouth Energy Cooperative
AECI	Associated Electric Cooperative Inc.
CARGILE	Cargill Power Markets, LLC
DUKE PWR	Duke Energy Corporation
EAGLE EN	EDF Trading North America, LLC
ENDURE	Endure Energy, LLC
EXELON	Exelon Generation Company
FPC	Duke Energy Florida
FPL	Florida Power & Light Company
MACQUARI	Macquarie Group
MERCURIA	Mercuria Energy Group
MISO	Midwest Independent System Operator, Inc.
MORGAN	Morgan Stanley Capital Group
NCEMC	North Carolina Electric Membership Corporation
NOBLEAGP	Noble Americas Gas and Power Corporation
OPC	Oglethorpe Power Corporation
ORLANDO	Orlando Utilities Commission
PJM	PJM Interconnection LLC.
REMC	Rainbow Energy Marketing Corporation
SCE&G	South Carolina Electric & Gas
SEC	Seminole Electric Cooperative
SEPA	Southeastern Power Administration
TAL	City of Tallahassee
TEA	The Energy Authority
TECO	Tampa Electric Company
TENASKA	Tenaska
TVA	Tennessee Valley Authority
WRI	Westar Energy

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: **Fuel and Purchased Power Cost**)
Recovery Clause with Generating)
Performance Incentive Factor)

Docket No.: **20210001-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by electronic mail this 20th day of January, 2021 to the following:

Florida Public Utilities Company
Florida Division of Chesapeake
Utilities Corp
Mike Cassel, Director
Regulatory and Governmental Affairs
1750 SW 14th Street, Suite 200
Fernandina Beach, FL 32034
mcassel@fpuc.com

PCS Phosphate – White Springs
c/o Stone Mattheis Xenopoulos
& Brew, P.C.
James W. Brew/Laura Baker
Eighth Floor, West Tower
1025 Thomas Jefferson St, NW
Washington, DC 20007
jbrew@smxblaw.com
lwb@smxblaw.com

Duke Energy Florida
Dianne M. Triplett
299 First Avenue North
St. Petersburg, FL 33701
Dianne.triplett@duke-energy.com

Florida Power & Light Company
Maria J. Moncada
David Lee
700 Universe Boulevard (LAW/JB)
Juno Beach, FL 33408-0420
Maria.moncada@fpl.com
David.Lee@fpl.com

Florida Power & Light Company
Kenneth Hoffman
134 West Jefferson Street
Tallahassee, FL 32301
Kenneth.Hoffman@fpl.com

Ausley Law Firm
James D. Beasley
J. Jeffry Wahlen
Malcolm N. Means
Post Office Box 391
Tallahassee, FL 32302
jbeasley@ausley.com
jwahlen@ausley.com
mmeans@ausley.com

Gunster Law Firm
Beth Keating
215 South Monroe Street, Suite 601
Tallahassee, FL 32301-1839
bkeating@gunster.com

Office of Public Counsel
J. R. Kelly/M. Fall-Fry
Patricia A. Christensen
Associate Public Counsel
c/o The Florida Legislature
111 W. Madison Street, Room 812
Tallahassee, FL 32399-1400
Kelly.jr@leg.state.fl.us
Christensen.patty@leg.state.fl.us
fall-fry.mireille@leg.state.fl.us

Duke Energy Florida, Inc.
Matthew R. Bernier
106 East College Avenue,
Suite 800
Tallahassee, FL 32301-7740
Matthew.bernier@duke-energy.com
FLRegulatoryLegal@duke-energy.com

Florida Industrial Power Users Group Tampa Electric Company
c/o Moyle Law Firm Ms. Paula K. Brown, Manager
Jon C. Moyle, Jr. Regulatory Coordination
118 North Gadsden Street P. O. Box 111
Tallahassee, FL 32301 Tampa, FL 33601-0111
jmoyle@moylelaw.com Regdept@tecoenergy.com
mqualls@moylelaw.com

Office of the General Counsel
Suzanne Brownless
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850
sbrownle@psc.state.fl.us


RUSSELL A. BADDERS
VP & Associate General Counsel
Florida Bar No. 007455
Russell.Badders@nexteraenergy.com
Maria Jose Moncada
Senior Attorney
Florida Bar No. 0773301
Maria.Moncada@fpl.com
Gulf Power Company
One Energy Place
Pensacola FL 32520-0100
(850) 444-6550
Attorney for Gulf Power

Schedule E-1A

GULF POWER COMPANY FUEL COST RECOVERY CLAUSE CALCULATION OF TRUE-UP

TO BE INCLUDED IN THE PERIOD JANUARY 2021 - DECEMBER 2021

(1)	(2)	(3)
Line No.	Description	Total
1.	Estimated over/(under)-recovery for the period January 2021 - December 2021 (Sch. E-1B, line C9)	\$ (46,341,367)
2.	Final over/(under)-recovery for the period January 2020 - December 2020 (Exhibit RLH-1, Schedule 1, line 3)	\$ 6,085,680
3.	Total over/(under)-recovery (Lines 1 + 2) ⁽¹⁾ To be included in January 2022 - December 2022	\$ (40,255,688)
4.	Jurisdictional kWh sales for the period January 2022 - December 2022	10,843,037,000
5.	True-Up Factor (Line 3/Line 4) x 100(¢/kWh)	0.3713

GULF POWER COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1) Line No.	(2) Description	(3) January Actual	(4) February Actual	(5) March Actual	(6) April Actual	(7) May Actual	(8) June Actual	(9) July Estimated	(10) August Estimated	(11) September Estimated	(12) October Estimated	(13) November Estimated	(14) December Estimated	(15) Total Period
A 1	Fuel Cost of System Generation	21,380,372	28,880,779	16,752,943	15,418,157	16,068,474	23,133,599	30,688,990	30,629,736	26,854,435	22,006,253	19,753,844	20,462,870	272,030,452
1a	Fuel Cost of Hedging Settlement	0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Wholesale kWh Sales Credit	(632,992)	(1,012,728)	(494,002)	(449,863)	(671,041)	(858,321)	(882,679)	(865,188)	(767,987)	(648,648)	(618,312)	(728,329)	(8,630,090)
2	Fuel Cost of Power Sold	(10,784,813)	(12,361,915)	(8,401,282)	(1,425,250)	(2,625,205)	(4,906,523)	(12,054,644)	(12,511,824)	(12,818,118)	(4,418,633)	(10,062,985)	(8,307,275)	(100,678,467)
3	Fuel Cost of Purchased Power	15,678,283	14,664,963	17,380,603	13,495,941	14,988,416	18,523,922	20,661,389	21,833,101	23,657,357	15,092,043	18,479,244	16,187,623	210,642,884
3a	Demand & Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
3b	Energy Payments to Qualified Facilities	241,981	283,198	186,301	303,835	279,402	439,569	0	0	0	0	0	0	1,734,285
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Generation	211,836	273,942	213,193	221,111	170,207	166,915	157,259	157,259	152,193	157,259	152,193	157,259	2,190,625
6	Adjustments to Fuel Cost	(66,102)	(56,448)	(168,779)	259,205	0	0	0	0	0	0	0	0	(32,124)
7	TOTAL FUEL & NET POWER TRANSACTIONS	26,028,565	30,671,791	25,468,977	27,823,134	28,210,253	36,499,160	38,570,315	39,243,084	37,077,880	32,188,274	27,703,984	27,772,148	377,257,564
B 1	Jurisdictional kWh Sales	845,524,629	770,762,557	740,914,413	725,199,507	921,217,470	1,028,037,836	1,142,081,000	1,140,336,000	1,077,518,000	916,091,000	760,923,000	784,724,000	10,853,329,412
2	Non-Jurisdictional kWh Sales	25,558,119	22,278,124	21,218,738	19,563,377	24,843,492	28,026,888	29,068,000	28,492,000	25,291,000	21,361,000	20,362,000	23,985,000	290,047,738
3	TOTAL SALES (Lines B1 + B2)	871,082,748	793,040,681	762,133,151	744,762,884	946,060,962	1,056,064,724	1,171,149,000	1,168,828,000	1,102,809,000	937,452,000	781,285,000	808,709,000	11,143,377,150
4	Jurisdictional % of Total Sales (Line B1/B3)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
C 1	Jurisdictional Fuel Recovery Revenue (1) (Net of Revenue Taxes)	25,464,397	23,376,455	22,454,384	21,752,114	27,873,521	32,769,548	34,842,646	34,789,410	32,872,956	27,948,136	23,214,265	23,940,387	331,298,217
2	True-Up Provision	(91,639)	(91,641)	(91,641)	(91,641)	(91,641)	(91,641)	(91,641)	(91,641)	(91,641)	(91,641)	(91,641)	(91,641)	(1,099,690)
2a	Incentive Provision	(5,185)	(5,182)	(5,182)	(5,182)	(5,182)	(5,182)	(5,182)	(5,182)	(5,182)	(5,182)	(5,182)	(5,182)	(62,187)
3	FUEL REVENUE APPLICABLE TO PERIOD	25,367,573	23,279,632	22,357,561	21,655,291	27,776,698	32,672,725	34,745,823	34,692,587	32,776,133	27,851,313	23,117,442	23,843,564	330,136,340
4	Fuel & Net Power Transactions (Line A7)	26,028,565	30,671,791	25,468,977	27,823,134	28,210,253	36,499,160	38,570,315	39,243,084	37,077,880	32,188,274	27,703,984	27,772,148	377,257,564
5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0012)	26,059,799	30,708,597	25,499,539	27,856,522	28,244,106	36,542,959	38,616,599	39,290,176	37,122,374	32,226,900	27,737,228	27,805,475	377,710,274
6	Over/(Under) Recovery (Line C3-C5)	(692,226)	(7,428,965)	(3,141,978)	(6,201,231)	(467,408)	(3,870,234)	(3,870,776)	(4,597,589)	(4,346,241)	(4,375,587)	(4,619,786)	(3,961,911)	(47,573,934)
7	Interest Provision	377	139	(268)	(586)	(509)	(657)	(1,133)	(1,411)	(1,704)	(1,990)	(2,286)	(2,567)	(12,595)
8	Adjustments	1,245,162	0	0	0	0	0	0	0	0	0	0	0	1,245,162
9	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2021 - DECEMBER 2021													(46,341,367)

* (Gain)/Loss on sales of natural gas and contract dispute litigation

Notes 1: Projected Revenues based on the current approved 2021 Fuel Factor excluding revenue taxes of: 3.0508 ¢/KWH
Total may not add due to rounding

GULF POWER COMPANY
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS

OF THE FUEL COST RECOVERY FACTOR

(1) Line No.	(2) Description	(3) (4) (5) (6)				(7) (8) (9) (10)				(11) (12) (13) (14)			
		Dollars				kWh				¢/kWh			
		Estimated Actual	Estimated Original	Difference		Estimated Actual	Estimated Original	Difference		Estimated Actual	Estimated Original	Difference	
				Amount	%			Amount	%			Amount	%
1	Fuel Cost of System Net Generation	272,030,452	246,764,669	25,265,783	10.24	9,188,857,493	9,729,429,000	(540,571,507)	(5.56)	2.9604	2.5363	0.4241	16.72
1a	Fuel Cost of Hedging Settlement	0	0	0	0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1b	Wholesale kWh Sales Credit	(8,630,090)	(8,905,923)	275,833	(3.10)	(290,047,738)	(293,286,000)	3,238,262	(1.10)	0.0000	3.0366	(3.0366)	(100.00)
2	Other Generation	2,190,625	3,104,447	(913,822)	(29.44)	79,568,507	113,508,000	(33,939,493)	(29.90)	2.7531	2.7350	0.0181	0.66
3	Adjustments to Fuel Cost	(32,124)	0	(32,124)	0	0	0	0	0	N/A	N/A	N/A	N/A
4	Total Cost of Generated Power	265,558,862	240,963,193	24,595,669	10.21	8,978,378,262	9,549,651,000	(571,272,738)	(5.98)	2.9578	2.5233	0.4345	17.22
5	Energy Cost of Other Economy Purchases (Nonbroker)	210,642,884	210,320,693	322,191	0.15	6,334,003,198	7,142,927,000	(808,923,802)	(11.32)	3.3256	2.9445	0.3811	12.94
6	Energy Payments to Qualifying Facilities	1,734,285	0	1,734,285	0	59,818,949	0	59,818,949	0	2.8992	0.0000	2.8992	100.00
7	Total Cost of Purchased Power	212,377,170	210,320,693	2,056,477	0.98	6,393,822,147	7,142,927,000	(749,104,853)	(10.49)	3.3216	2.9445	0.3771	12.81
8	Total Available (Line 4 + Line 7)	477,936,032	451,283,886	26,652,146	5.91	15,372,200,409	16,692,578,000	(1,320,377,591)	(7.91)	3.1091	2.7035	0.4056	15.00
9	Fuel Cost of Economy Sales	(2,313,778)	(2,017,510)	(296,268)	14.68	(75,421,863)	(84,034,000)	8,612,137	(10.25)	3.0678	2.4008	0.6670	27.78
10	Gain on Economy Sales	(385,303)	0	(385,303)	(100.00)	0	0	N/A	N/A	N/A	N/A	N/A	N/A
11	Fuel Cost of Other Power Sales	(97,979,386)	(123,432,062)	25,452,676	(20.62)	(3,793,430,228)	(5,281,374,000)	1,487,943,772	(28.17)	2.5829	2.3371	0.2458	10.52
12	Total Gains on Power Sales	(100,678,467)	(125,449,572)	24,771,105	(19.75)	(3,868,852,091)	(5,365,408,000)	1,496,555,909	(27.89)	2.6023	2.3381	0.2642	11.30
13	Total Fuel & Net Power Transactions	377,257,565	325,834,314	51,423,251	15.78	11,503,348,318	11,327,170,000	176,178,318	1.56	3.2795	2.8766	0.4029	14.01
14	Company Use *	467,517	424,557	42,960	10.12	14,255,742	14,759,000	(503,258)	(3.41)	3.2795	2.8766	0.4029	14.01
15	T & D Losses *	11,337,705	16,751,679	(5,413,974)	(32.32)	345,714,426	582,343,000	(236,628,574)	(40.63)	3.2795	2.8766	0.4029	14.01
16	TERRITORIAL (SYSTEM) SALES	377,257,565	325,834,314	51,423,251	15.78	11,143,378,150	10,730,068,000	413,310,150	3.85	3.3855	3.0366	0.3489	11.49
17	Other Wholesale KWH Sales	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
18	Jurisdictional Sales	377,257,565	325,834,314	51,423,251	15.78	11,143,378,150	10,730,068,000	413,310,150	3.85	3.3855	3.0366	0.3489	11.49
19	Jurisdictional Sales Adj. for Line Losses (Line 18 x 1.0012)	377,710,274	326,225,315	51,484,959	15.78	11,143,378,150	10,730,068,000	413,310,150	3.85	3.3895	3.0403	0.3492	11.49
20	TRUE-UP **	1,099,690	1,099,690	0	0.00	11,143,378,150	10,730,068,000	413,310,150	3.85	0.0099	0.0102	(0.0003)	(2.94)
21	TOTAL JURISDICTIONAL FUEL COST	378,809,964	327,325,005	51,484,959	15.73	11,143,378,150	10,730,068,000	413,310,150	3.85	3.3994	3.0505	0.3489	11.44
22	Fuel Factor Adjusted for Revenue Taxes									3.4018	3.0527	0.3492	11.44
23	GPIF Reward / (Penalty) **	62,277	62,277	0	0.00	11,143,378,150	10,730,068,000	413,310,150	3.85	0.0006	0.0006	0.0000	0.00
28	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.4024	3.0533	0.3491	11.43
29	FUEL FACTOR ROUNDED TO NEAREST .001(¢/kWh)									3.4020	3.0530	0.3490	11.43

Totals may not add due to rounding

* Included for informational purposes only.

** ¢/kWh calculation based on jurisdictional kWh sales.

Note: Amounts included in the Estimated/Actual column represent 6 months actual and 6 months estimate.

Jurisdictional Loss Multiplier

1.0012

Revenue Tax Factor

1.00072

GULF POWER COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	TOTAL
1	Fuel Cost of System Generation ⁽¹⁾	21,380,372	28,880,779	16,752,943	15,418,157	16,068,474	23,133,599	30,688,990	30,629,736	26,854,435	22,006,253	19,753,844	20,462,870	272,030,452
1a	Other Generation	211,836	273,942	213,193	221,111	170,207	166,915	157,259	157,259	152,193	157,259	152,193	157,259	2,190,625
1b	Wholesale kWh Sales Credit	(632,992)	(1,012,728)	(494,002)	(449,863)	(671,041)	(858,321)	(882,679)	(865,188)	(767,987)	(648,648)	(618,312)	(728,329)	(8,630,090)
2	Fuel Cost of Power Sold	(10,784,813)	(12,361,915)	(8,401,282)	(1,425,250)	(2,625,205)	(4,906,523)	(12,054,644)	(12,511,824)	(12,818,118)	(4,418,633)	(10,062,985)	(8,307,275)	(100,678,467)
3	Fuel Cost of Purchased Power	15,678,283	14,660,908	17,380,603	13,495,940	14,988,416	18,523,922	20,661,389	21,833,101	23,657,357	15,092,043	18,479,244	16,187,623	210,638,829
3a	Demand & Non-Fuel Cost of Pur Power	0	0	0	0	0	0	0	0	0	0	0	0	0
3b	Qualifying Facilities	241,981	287,253	186,301	303,835	279,402	439,569	0	0	0	0	0	0	1,738,340
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Hedging Settlement	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Adjustment to Fuel Cost	(66,102)	(56,448)	(168,779)	259,205	0	0	0	0	0	0	0	0	(32,124)
7	Total Fuel & Net Power Trans.	\$ 26,028,565	\$ 30,671,791	\$ 25,468,976	\$ 27,823,134	\$ 28,210,253	\$ 36,499,160	\$ 38,570,315	\$ 39,243,084	\$ 37,077,880	\$ 32,188,274	\$ 27,703,984	\$ 27,772,148	\$ 377,257,565
8	System kWh Sold	871,082,748	793,040,681	762,133,151	744,762,884	946,060,962	1,056,064,724	1,171,149,000	1,168,828,000	1,102,809,000	937,452,000	781,285,000	808,709,000	11,143,377,150
8a	Jurisdictional % of Total Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
9	Cost per kWh Sold (\$/kWh)	2.9881	3.8676	3.3418	3.7358	2.9819	3.4561	3.2934	3.3575	3.3621	3.4336	3.5460	3.4341	3.3855
9a	Jurisdictional Loss Multiplier	1.0012	1.0012	1.0012	1.0012	1.0012	1.0012	1.0012	1.0012	1.0012	1.0012	1.0012	1.0012	1.0012
9b	Jurisdictional Cost (\$/kWh)	2.9917	3.8722	3.3458	3.7403	2.9855	3.4602	3.2974	3.3615	3.3661	3.4377	3.5503	3.4382	3.3896
10	GPIF (\$/kWh) *	0.0006	0.0007	0.0007	0.0007	0.0006	0.0005	0.0005	0.0005	0.0005	0.0006	0.0007	0.0007	0.0006
11	True-Up (\$/kWh) *	0.0108	0.0119	0.0124	0.0126	0.0099	0.0089	0.0080	0.0080	0.0085	0.0100	0.0120	0.0117	0.0101
12	TOTAL	3.0031	3.8848	3.3589	3.7536	2.9960	3.4696	3.3059	3.3700	3.3751	3.4483	3.5630	3.4506	3.4003
13	Revenue Tax Factor	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
14	Recovery Factor Adjusted for Taxes	3.0053	3.8876	3.3613	3.7563	2.9982	3.4721	3.3083	3.3724	3.3775	3.4508	3.5656	3.4531	3.4027
16	Recovery Factor Rounded to the Nearest .001 \$/kWh	3.005	3.888	3.361	3.756	2.998	3.472	3.308	3.372	3.378	3.451	3.566	3.453	3.403

* \$/kWh calculations based on jurisdictional kWh sales

⁽¹⁾ Includes portion of Gulf's 25% ownership of Scherer Unit 3

Total may not add due to rounding

GULF POWER COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	TOTAL
<u>FUEL COST - NET GEN. (\$)</u>														
1	LIGHTER OIL (B.L.)	29,515	126,543	43,804	13,951	83,681	31,780	29,076	29,452	29,851	24,018	60,938	62,160	564,770
2	COAL	4,563,261	3,936,182	3,795,698	8,127,582	1,581,822	3,206,283	3,983,565	4,097,942	3,817,564	3,629,622	4,194,654	7,108,085	52,042,259
2a	Coal at Scherer	(154,910)	1,030,156	(7,252)	(213,141)	459,962	1,700,469	2,617,129	2,608,261	1,545,871	0	0	0	9,586,545
3	GAS - Generation	17,072,292	23,972,501	13,055,842	7,404,301	13,973,417	18,257,819	24,135,782	23,970,643	21,535,185	18,429,175	15,572,288	13,369,187	210,748,432
4	GAS (B.L.)	3,414	22,476	0	221,071	38,903	22,380	0	0	0	0	0	0	308,244
5	Landfill Gas	78,636	62,900	78,043	66,610	100,896	75,142	80,697	80,697	78,157	80,697	78,157	80,697	941,330
6	OIL - C.T.	0	3,963	0	18,895	0	6,641	0	0	0	0	0	0	29,499
7	TOTAL (\$)	21,592,208	29,154,720	16,966,136	15,639,268	16,238,681	23,300,514	30,846,249	30,786,995	27,006,628	22,163,512	19,906,037	20,620,129	274,221,077
<u>SYSTEM NET GEN. (MWH)</u>														
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL	151,160	134,550	117,976	152,745	92,510	110,598	144,916	146,357	137,503	131,174	151,115	262,887	1,733,491
9a	Coal at Scherer	(688)	33,444	(702)	(699)	12,537	45,472	86,546	86,138	50,983	0	0	0	313,031
10	GAS	698,726	636,595	554,758	278,325	486,502	564,904	763,879	753,690	687,875	605,311	555,247	435,731	7,021,543
11	Landfill Gas	2,130	1,729	2,153	1,871	2,135	1,992	2,097	2,097	2,031	2,097	2,031	2,097	24,460
12	OIL - C.T.	(9)	37	(9)	35	(11)	16	0	0	0	0	0	0	59
13	Solar	9,178	8,954	14,463	15,710	19,677	15,530	19,415	18,294	16,424	15,891	12,454	9,851	175,841
14	TOTAL (MWH)	860,497	815,309	688,639	447,987	613,350	738,513	1,016,853	1,006,576	894,816	754,473	720,847	710,566	9,268,426
<u>UNITS OF FUEL BURNED</u>														
15	LIGHTER OIL (BBL)	470	1,799	635	199	1,042	339	376	376	376	309	762	762	7,445
16	COAL excl. Scherer (TON) (2)	93,432	79,999	78,184	97,514	54,648	67,706	81,888	81,728	77,316	74,349	86,646	147,879	1,021,289
17	GAS-all (MCF) (1)	5,470,962	5,581,376	3,943,029	2,262,833	3,629,258	4,622,799	6,604,362	6,510,493	5,803,370	4,773,181	4,246,831	3,498,457	56,946,951
18	OIL - C.T. (BBL)	0	45	0	214	0	75	0	0	0	0	0	0	334
<u>BTU'S BURNED (MMBTU)</u>														
19	COAL + GAS B.L. + OIL B.L.	1,604,868	1,818,600	1,370,268	1,693,919	1,144,957	1,741,501	2,426,672	2,436,622	1,963,660	1,343,823	1,563,368	2,657,713	21,765,971
20	GAS-Generation (1)	5,620,810	5,731,545	4,052,271	2,250,122	3,715,975	4,740,372	6,604,362	6,510,493	5,803,370	4,773,181	4,246,831	3,498,457	57,547,789
21	OIL - C.T.	0	262	0	1,244	0	436	0	0	0	0	0	0	1,942
22	TOTAL (MMBTU)	7,225,678	7,550,407	5,422,539	3,945,285	4,860,932	6,482,309	9,031,034	8,947,115	7,767,030	6,117,004	5,810,199	6,156,170	79,315,702

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.
(2) Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and \$ only.

GULF POWER COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	TOTAL
<u>GENERATION MIX (% MWH)</u>														
23	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	COAL	17.49	20.60	17.03	33.94	17.13	21.13	22.76	23.09	21.05	17.38	20.96	36.99	22.08
25	GAS-Generation	81.19	78.09	80.56	62.12	79.31	76.50	75.12	74.88	76.88	80.23	77.03	61.31	75.76
26	Landfill Gas	0.25	0.21	0.31	0.42	0.35	0.27	0.21	0.21	0.23	0.28	0.28	0.31	0.26
27	OIL - C.T.	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Solar	1.07	1.10	2.10	3.51	3.21	2.10	1.91	1.82	1.84	2.11	1.73	1.39	1.90
29	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
<u>FUEL COST \$ / UNIT</u>														
30	LIGHTER OIL (\$/BBL)	62.80	70.34	68.98	70.10	80.31	93.89	77.31	78.30	79.37	77.82	79.93	81.53	75.86
31	COAL (\$/TON) (2)	48.84	49.20	48.55	83.35	28.95	47.36	48.65	50.14	49.38	48.82	48.41	48.07	50.96
32	GAS + B.L. (\$/MCF) (1)	3.07	4.25	3.26	3.27	3.81	3.92	3.63	3.66	3.68	3.83	3.63	3.78	3.67
33	OIL - C.T.	0.00	88.06	0.00	88.29	0.00	88.55	0.00	0.00	0.00	0.00	0.00	0.00	88.32
<u>FUEL COST \$ / MMBTU</u>														
34	COAL + GAS B.L. + OIL B.L.	2.86	2.57	2.80	4.94	2.10	2.85	2.73	2.76	2.75	2.72	2.72	2.70	2.87
35	GAS-Generation (1)	3.00	4.13	3.17	3.19	3.71	3.82	3.63	3.66	3.68	3.83	3.63	3.78	3.62
36	OIL - C.T.	0.00	15.12	0.00	15.19	0.00	15.23	0.00	0.00	0.00	0.00	0.00	0.00	15.19
37	TOTAL (\$/MMBTU)	2.95	3.82	3.08	3.89	3.28	3.56	3.39	3.41	3.45	3.58	3.39	3.31	3.42
<u>BTU BURNED BTU / KWH</u>														
38	COAL + GAS B.L. + OIL B.L.	10,666	10,825	11,684	11,141	10,899	11,158	10,484	10,480	10,418	10,245	10,346	10,110	10,636
39	GAS-Generation (1)	8,140	9,126	7,422	8,341	7,733	8,475	8,711	8,704	8,505	7,961	7,725	8,136	8,290
40	OIL - C.T.	0	7,081	0	35,543	0	27,250	0	0	0	0	0	0	32,915
41	TOTAL (BTU/KWH)	8,500	9,379	8,001	9,017	8,032	8,868	8,950	8,958	8,754	8,192	8,146	8,760	8,655
<u>FUEL COST CENTS / KWH</u>														
42	COAL + GAS B.L. + OIL B.L.	2.95	3.04	3.27	5.36	2.06	3.18	2.86	2.90	2.86	2.79	2.82	2.73	3.05
43	GAS-Generation	2.44	3.77	2.35	2.66	2.87	3.23	3.16	3.18	3.13	3.04	2.80	3.07	3.00
44	Landfill Gas	3.69	3.64	3.62	3.56	4.73	3.77	3.85	3.85	3.85	3.85	3.85	3.85	3.85
45	OIL - C.T.	0.00	10.71	0.00	53.99	0.00	41.51	0.00	0.00	0.00	0.00	0.00	0.00	50.00
46	TOTAL (¢/KWH)	2.51	3.58	2.46	3.49	2.65	3.16	3.03	3.06	3.02	2.94	2.76	2.90	2.96

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.
(2) Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and \$ only.

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: JANUARY 2021**

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100													
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	Crist 4	75	-	0.0%	100.0%	0.0%	N/A	-	-	-	-	0.00	0.00
2	Gas-G		(431)					-	-	-	-		0.00
3	Gas-S							-	-	-	-		0.00
4	Oil-S							-	-	-	-		0.00
5	Crist 5	75	-	0.0%	100.0%	0.0%	N/A	-	-	-	-	0.00	0.00
6	Gas-G		(431)					-	-	-	-		0.00
7	Gas-S							-	-	-	-		0.00
8	Oil-S							-	-	-	-		0.00
9	Crist 6	299		60.2%	98.8%	61.0%	11455.39812						
10	Gas-G		134,019					1,493,862	0	1,535,241	4,892,550	3.65	3.28
11	Gas-S		-					-	0	-	-		0.00
12	Oil-S							-	-	-	-		0.00
13	Crist 7	475		29.4%	59.4%	49.9%	11,160						
14	Gas-G		103,833					1,127,507	1,028	1,158,739	3,692,704	3.56	3.28
15	Gas-S							1,042	0	1,072	3,414		3.28
16	Oil-S							-	-	-	-		0.00
17	Smith 3	664	453,491	91.8%	98.0%	91.8%	6,454						
18	Gas-G							2,848,551	1,027	2,926,830	8,275,202	1.82	2.91
19	Smith A (1)	32	(9)	0.0%	100.0%	0.0%	-						
20	Oil							-	-	-	-	0.00	0.00
21	Scherer 3 (2)	215	(688)	0.0%	100.0%	0.0%	-						
22	Coal								-	-	-	0.00	0.00
23	Oil							-	-	-	-	0.00	0.00
24	Other Generation		8,245										
25	Gas										211,836	2.57	0.00
26	Perdido		2,130										
27	Landfill Gas										78,636	3.69	0.00
28	Blue Indigo		9,178										
29	Solar										-		
30	Daniel 1 (3)	251	83,031	44.5%	87.3%	50.0%	10,997						
31	Coal							51,200	8,917	913,084	2,504,181	3.02	48.91
32	Oil-S							1	138,184	8	88		88.00
33	Daniel 2 (3)	251	68,129	36.5%	90.5%	52.0%	10,914						
34	Coal							42,232	8,917	743,588	2,065,514	3.03	48.91
35	Oil-S							469	138,184	2,718	29,427		62.74
36	Gas,BL												
37	Gas												
38	Ltr. Oil												
39	Oil												
40	Total	2,337	860,497	49.5%	88.6%	55.0%	8,565			7,281,280	21,753,552	2.53	

Notes:

- (1) Smith A uses lighter oil
 (2) Represents Gulf's 25% Ownership
 (3) Represents Gulf's 50% Ownership

Adj. Units	Adj. Description	Adj. \$	cents/kWh
N/A	Daniel Railcar Track Deprec.	(6,995)	
	Crist coal inventory adjustment	560	
(55,602)	Scherer coal inventory adjustment	(154,910)	

Recoverable Fuel 21,592,208 2.51

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: FEBRUARY 2021**

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (\$/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	75		0.4%	100.0%	28.7%	41,726						
2	Gas-G		201					8,157	1,028	8,387	35,414	17.62	4.22
3	Gas-S							2,643	1,028	2,717	11,474		4.22
4	Oil-S							51	139,075	297	2,721		53.35
5	GCEC 5 ⁽⁴⁾	75		0.6%	99.5%	31.6%	30,923						
6	Gas-G		311					9,353	1,028	9,617	40,608	13.06	4.22
7	Gas-S							2,534	1,028	2,605	11,002		4.22
8	Oil-S							37	139,075	213	1,958		52.92
9	GCEC 6 ⁽⁴⁾	299		46.8%	90.9%	53.3%	11,623						
10	Gas-G		94,089					1,063,601	1,028	1,093,595	4,617,927	4.91	4.34
11	Gas-S		-					-	1,028	-	-		0.00
12	Oil-S							-	139,075	-	-		0.00
13	GCEC 7 ⁽⁴⁾	475		52.5%	95.0%	54.8%	10,892						
14	Gas-G		167,611					1,775,589	1,028	1,825,661	7,709,222	4.60	4.34
15	Gas-S							-	1,028	-	-		0.00
16	Oil-S							-	139,075	-	-		0.00
17	Smith 3	660	365,828	82.5%	98.0%	57.7%	7,638						
18	Gas-G							2,719,499	1,028	2,794,285	10,846,970	2.97	3.99
19	Smith A	32	37	0.2%	100.0%	112.0%	7,069						
20	Oil							45	138,388	262	3,963	10.71	88.07
21	Scherer 3 ⁽²⁾	215	33,444	23.1%	100.0%	57.7%	11,018						
22	Coal								8,526	368,490	1,030,156	3.08	2.80
23	Oil							369	138,500	2,149	31,334	0.00	84.92
24	Other Generation		8,555										
25	Gas										273,942	3.20	0.00
26	Perdido		1,729										
27	Landfill Gas										62,900	3.64	0.00
28	Blue Indigo		8,954										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	73,581	43.6%	78.2%	69.6%	10,503						
31	Coal							43,564	8,870	772,825	2,130,635	2.90	48.91
32	Oil-S							778	138,184	4,516	52,481		67.46
33	Daniel 2 ⁽³⁾	251	60,970	36.1%	63.6%	60.3%	10,850						
34	Coal							36,435	8,870	661,514	1,781,988	2.92	48.91
35	Oil-S							564	138,184	3,274	38,049		67.46
36	Gas,BL												
37	Gas												
38	Ltr. Oil											N/A	N/A
39	Oil												
40	Total	2,333	815,309	50.2%	91.0%	57.1%	9,379			7,550,407	28,682,744	3.52	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
N/A	Daniel Railcar Track Deprec.	(6,995)	
	Crist coal inventory adjustment	30,553	
	Crist Other Fuel Inventory adjustment	448,419	

Recoverable Fuel 29,154,721 3.58

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: MARCH 2021**

**Schedule E-4
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		2.9%	100.0%	33.0%	16,735						
2	Gas-G		1,693					27,555	1,028	28,332	85,057	5.02	3.00
3	Gas-S							-	1,028	-	-		0.00
4	Oil-S							54	139,075	314	2,920		54.07
5	GCEC 5 ⁽⁴⁾	78		0.0%	99.5%	0.0%	N/A						
6	Gas-G		(712)					-	1,028	-	-	0.00	0.00
7	Gas-S							-	1,028	-	-		0.00
8	Oil-S							-	139,075	-	-		0.00
9	GCEC 6 ⁽⁴⁾	315		12.2%	96.0%	54.5%	12,445						
10	Gas-G		28,498					344,919	1,028	354,646	1,064,697	3.74	3.09
11	Gas-S		-					-	1,028	-	-		0.00
12	Oil-S							-	139,075	-	-		0.00
13	GCEC 7 ⁽⁴⁾	496		19.9%	96.0%	54.4%	11,009						
14	Gas-G		73,170					783,422	1,028	805,514	2,418,267	3.30	3.09
15	Gas-S							-	1,028	-	-		0.00
16	Oil-S							-	139,075	-	-		0.00
17	Smith 3	660	443,343	90.4%	100.0%	89.9%	6,460						
18	Gas-G							2,787,133	1,028	2,863,779	9,274,628	2.09	3.33
19	Smith A	32	(9)	0.0%	70.5%	0.0%	-						
20	Oil							-	-	-	-	0.00	0.00
21	Scherer 3 ⁽²⁾	215	(702)	0.0%	61.2%	89.9%	-						
22	Coal								-	-	-	0.00	0.00
23	Oil							-	-	-	-	0.00	0.00
24	Other Generation		8,766										
25	Gas										213,193	2.43	0.00
26	Perdido		2,153										
27	Landfill Gas										78,043	3.62	0.00
28	Blue Indigo		14,463										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	41,307	22.1%	78.1%	53.3%	11,649						
31	Coal							27,668	8,696	481,202	1,335,441	3.23	48.27
32	Oil-S							569	138,184	3,307	40,050		70.39
33	Daniel 2 ⁽³⁾	251	76,670	41.1%	84.7%	46.2%	11,582						
34	Coal							50,516	8,696	887,970	2,438,236	3.18	48.27
35	Oil-S							12	138,184	69	835		69.58
36	Gas,BL												
37	Gas												
38	Ltr. Oil												
39	Oil											N/A	N/A
40	Total	2,376	688,639	39.0%	90.8%	63.3%	8,005			5,425,133	16,951,367	2.46	

Notes:

- (1) Smith A uses lighter oil
- (2) Represents Gulf's 25% Ownership
- (3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
N/A	Daniel Railcar Track Deprec.	(6,994.55)	
-	Crist coal inventory adjustment	29,016	
(2,594)	Scherer Coal Inventory adjustment	(7,252)	

Recoverable Fuel 16,966,136 2.46

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: APRIL 2021**

**Schedule E-4
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		0.0%	80.7%	0.0%	N/A						
2	Gas-G		(477)					-	-	-	-	0.00	0.00
3	Gas-S							-	-	-	-		0.00
4	Oil-S							-	139,075	-	-		0.00
5	GCEC 5 ⁽⁴⁾	78		0.8%	77.4%	43.6%	825,032						
6	Gas-G		434					353,120	-	358,064	1,143,066	263.38	3.19
7	Gas-S							68,294	-	69,250	221,071		3.19
8	Oil-S							21	139,075	118	1,136		54.10
9	GCEC 6 ⁽⁴⁾	315		0.0%	30.0%	0.0%	N/A						
10	Gas-G		(1,089)					-	-	-	-	0.00	0.00
11	Gas-S		-					-	-	-	-		0.00
12	Oil-S							-	139,075	-	-		0.00
13	GCEC 7 ⁽⁴⁾	496		0.0%	47.4%	0.0%	N/A						
14	Gas-G		(243)					-	-	-	-	0.00	0.00
15	Gas-S							-	-	-	-		0.00
16	Oil-S							-	139,075	-	-		0.00
17	Smith 3	660	271,140	57.1%	63.4%	82.3%	6,978						
18	Gas-G							1,841,419	1,028	1,892,058	6,040,123	2.23	3.28
19	Smith A	32	35	0.2%	98.1%	0.0%	35,538						
20	Oil							214	138,388	1,244	18,895	53.99	88.29
21	Scherer 3 ⁽²⁾	215	(699)	0.0%	93.3%	0.0%	-						
22	Coal							-	-	-	-	0.00	0.00
23	Oil							-	-	-	-	0.00	0.00
24	Other Generation		8,560										
25	Gas										221,111	2.58	0.00
26	Perdido		1,871										
27	Landfill Gas										66,610	3.56	0.00
28	Blue Indigo		15,710										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	82,869	45.9%	84.7%	51.5%	11,149						
31	Coal							53,026	8,712	923,936	2,524,961	3.05	47.62
32	Oil-S							3	138,184	19	230		76.67
33	Daniel 2 ⁽³⁾	251	69,877	38.7%	69.6%	52.8%	11,106						
34	Coal							44,488	8,712	776,083	2,118,400	3.03	47.62
35	Oil-S							175	138,184	1,017	12,585		71.91
36	Gas,BL												
37	Gas												
38	Ltr. Oil												
39	Oil											N/A	N/A
40	Total	2,376	447,987	26.2%	62.7%	35.3%	9,191			4,021,789	12,368,188	2.76	

Notes:

- (1) Smith A uses lighter oil
- (2) Represents Gulf's 25% Ownership
- (3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
N/A	Daniel Railcar Track Deprec.	(6,994.55)	
-	Crist coal inventory adjustment	3,491,215	
(76,504)	Scherer Coal Inventory adjustment	(213,142)	

Recoverable Fuel 15,639,268 3.49

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: MAY 2021**

**Schedule E-4
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		2.4%	100.0%	28%	20,358						
2	Gas-G		1,401					27,854	1,024	28,522	105,947	7.56	3.71
3	Gas-S							1,177	1,024	1,206	4,480		3.71
4	Oil-S							11	139,075	67	649		59.00
5	GCEC 5 ⁽⁴⁾	78		3.3%	100.0%	24.2%	16,586						
6	Gas-G		1,911					30,953	1,024	31,696	117,737	6.16	3.71
7	Gas-S							1,384	1,024	1,417	5,264		3.71
8	Oil-S							23	139,075	129	1,249		54.30
9	GCEC 6 ⁽⁴⁾	315		15.6%	38.1%	44.4%	12,925						
10	Gas-G		36,561					461,479	1,024	472,554	1,755,330	4.80	3.80
11	Gas-S		-					5,365	1,024	5,494	20,408		3.80
12	Oil-S							-	139,075	-	-		0.00
13	GCEC 7 ⁽⁴⁾	496		4.4%	47.4%	37.3%	12,610						
14	Gas-G		16,244					200,037	1,024	204,838	760,883	4.68	3.80
15	Gas-S							2,301	1,024	2,356	8,752		3.80
16	Oil-S							-	139,075	-	-		0.00
17	Smith 3	660	424,394	86.4%	100.0%	85.9%	7,018						
18	Gas-G							2,898,708	1,027	2,978,365	11,063,313	2.61	3.82
19	Smith A	32	(11)	0.0%	100.0%	0.0%	-						
20	Oil							-	-	-	-	0.00	0.00
21	Scherer 3 ⁽²⁾	215	12,537	7.8%	100.0%	34.1%	12,533						
22	Coal								8,712	157,130	459,962	3.67	2.93
23	Oil							409	138,500	2,377	37,324	0.00	91.26
24	Other Generation		5,991										
25	Gas										170,207	2.84	0.00
26	Perdido		2,135										
27	Landfill Gas										100,896	4.73	0.00
28	Blue Indigo		19,677										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	94,696	50.7%	69.7%	59.5%	10,257						
31	Coal							54,648	8,887	971,305	2,550,261	2.69	46.67
32	Oil-S							599	138,184	3,476	44,460		74.22
33	Daniel 2 ⁽³⁾	251	(2,186)	0.0%	0.0%	0.0%	-						
34	Coal							-	8,887	-	-	0.00	0.00
35	Oil-S							-	-	-	-		0.00
36	Gas,BL												
37	Gas												
38	Ltr. Oil												
39	Oil											N/A	N/A
40	Total	2,376	613,350	34.7%	67.0%	48.6%	8,032			4,860,932	17,207,120	2.81	

Notes:

- (1) Smith A uses lighter oil
- (2) Represents Gulf's 25% Ownership
- (3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
N/A	Daniel Railcar Track Deprec.	(6,994.55)	
-	Crist coal inventory adjustment	(723,815)	
-	Daniel coal inventory adjustment	(237,629)	

Recoverable Fuel 16,238,681 2.65

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: JUNE 2021**

**Schedule E-4
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		0.0%	100.0%	0.0%	N/A						
2	Gas-G		(257)					-	-	-	-	0.00	0.00
3	Gas-S							-	-	-	-		0.00
4	Oil-S							-	139,075	-	-		0.00
5	GCEC 5 ⁽⁴⁾	78		0.0%	100.0%	0.0%	N/A						
6	Gas-G		(257)					-	-	-	-	0.00	0.00
7	Gas-S							-	-	-	-		0.00
8	Oil-S							-	139,075	-	-		0.00
9	GCEC 6 ⁽⁴⁾	315		32.6%	86.7%	41.4%	12,476						
10	Gas-G		73,953					899,748	-	922,656	3,521,176	4.76	3.91
11	Gas-S		-					2,995	-	3,071	11,720		3.91
12	Oil-S							-	139,075	-	-		0.00
13	GCEC 7 ⁽⁴⁾	496		20.5%	100.0%	36.0%	12,246						
14	Gas-G		73,323					875,630	1,025	897,924	3,426,789	4.67	3.91
15	Gas-S							2,724	-	2,793	10,660		3.91
16	Oil-S							-	139,075	-	-		0.00
17	Smith 3	660	412,594	86.8%	97.0%	88.6%	7,077						
18	Gas-G							2,841,702	1,027	2,919,792	11,142,940	2.70	3.92
19	Smith A	32	16	0.1%	100.0%	97.4%	27,245						
20	Oil							75	138,388	436	6,641	41.51	88.55
21	Scherer 3 ⁽²⁾	215	45,472	29.4%	100.0%	40.7%	11,832						
22	Coal								8,712	538,028	1,700,469	3.74	3.16
23	Oil							331	138,500	1,928	31,229	0.00	94.35
24	Other Generation		5,548										
25	Gas										166,915	3.01	0.00
26	Perdido		1,992										
27	Landfill Gas										75,142	3.77	0.00
28	Blue Indigo		15,530										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	112,958	62.5%	85.4%	68.0%	10,585						
31	Coal							67,706	8,830	1,195,638	3,213,277	2.84	47.46
32	Oil-S							7	138,184	43	551		78.71
33	Daniel 2 ⁽³⁾	251	(2,360)	0.0%	0.0%	0.0%	-						
34	Coal							-	8,830	-	-	0.00	0.00
35	Oil-S							-	-	-	-		0.00
36	Gas,BL												
37	Gas												
38	Ltr. Oil												
39	Oil											N/A	N/A
40	Total	2,376	738,513	43.2%	85.3%	49.8%	8,868			6,482,309	23,307,508	3.16	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
N/A	Daniel Railcar Track Deprec.	(6,995)	

Recoverable Fuel 23,300,514 3.16

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Notes:

- (1) Smith A uses lighter oil
- (2) Represents Gulf's 25% Ownership
- (3) Represents Gulf's 50% Ownership

Recoverable Fuel	30,846,249	3.03
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**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: AUGUST 2021**

**Schedule E-4
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		48.9%	92.4%	9.1%	13,147						
2	Gas-G		28,370					365,675	1,020	372,989	1,265,367	4.46	3.46
3	Gas-S							-	-	-	-		N/A
4	Oil-S							-	-	-	-		N/A
5	GCEC 5 ⁽⁴⁾	78		2.0%	92.4%	9.1%	13,152						
6	Gas-G		1,160					14,957	1,020	15,256	122,055	10.52	8.16
7	Gas-S							-	-	-	-		N/A
8	Oil-S							-	-	-	-		N/A
9	GCEC 6 ⁽⁴⁾	315		43.0%	92.4%	60.6%	11,417						
10	Gas-G		100,872					1,129,063	1,020	1,151,644	3,753,951	3.72	3.32
11	Gas-S							-	-	-	-		N/A
12	Oil-S							-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	496		39.0%	92.4%	65.3%	11,468						
14	Gas-G		143,976					1,618,684	1,020	1,651,057	5,350,075	3.72	3.31
15	Gas-S							-	-	-	-		N/A
16	Oil-S							-	-	-	-		N/A
17	Smith 3	660	473,600	96.4%	93.5%	94.4%	7,009						
18	Gas-G							3,254,458	1,020	3,319,547	13,321,937	2.81	4.09
19	Smith A	32	-	0.0%	93.5%	0.0%	N/A						
20	Oil							-	-	-	-	N/A	N/A
21	Scherer 3 ⁽²⁾	215	86,138	53.8%	92.9%	9.5%	10,955						
22	Coal								8,539	943,664	2,608,261	3.03	N/A
23	Oil							-	-	-	-		
24	Other Generation		5,712										
25	Gas										157,259		
26	Perdido		2,097										
27	Landfill Gas										80,697		
28	Blue Indigo		18,294										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	146,357	78.4%	92.3%	23.5%	10,186						
31	Coal							81,728	9,120	1,490,756	4,097,941	2.80	50.14
32	Oil-S							-	-	-	-		
33	Daniel 2 ⁽³⁾	251	-	0.0%	60.5%	0.0%	N/A						
34	Coal							-	-	-	-	N/A	N/A
35	Oil-S							-	-	-	-		
36	Gas,BL												
37	Gas							-	-	-	-	N/A	N/A
38	Ltr. Oil												
39	Oil							376	139,400	2,202	29,452	N/A	78.33
40	Total	2,376	1,006,576	56.9%	89.4%	51.8%	8,889			8,947,115	30,786,995	3.06	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
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Recoverable Fuel 30,786,995 3.06

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: SEPTEMBER 2021**

**Schedule E-4
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		1.7%	92.4%	0.0%	13,152						
2	Gas-G		960					12,378	1,020	12,626	111,131	11.58	8.98
3	Gas-S							-	-	-	-		N/A
4	Oil-S							-	-	-	-		N/A
5	GCEC 5 ⁽⁴⁾	78		0.0%	92.4%	0.0%	N/A						
6	Gas-G		-					-	-	-	70,931	0	N/A
7	Gas-S							-	-	-	-		N/A
8	Oil-S							-	-	-	-		N/A
9	GCEC 6 ⁽⁴⁾	315		42.9%	92.4%	5.6%	11,423						
10	Gas-G		97,348					1,090,160	1,020	1,111,964	3,611,312	3.71	3.31
11	Gas-S							-	-	-	-		N/A
12	Oil-S							-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	496		35.7%	92.4%	61.5%	11,687						
14	Gas-G		127,639					1,462,495	1,020	1,491,745	4,820,497	3.78	3.30
15	Gas-S							-	-	-	-		N/A
16	Oil-S							-	-	-	-		N/A
17	Smith 3	660	456,400	96.0%	93.5%	94.3%	6,983						
18	Gas-G							3,124,544	1,020	3,187,035	12,769,121	2.80	4.09
19	Smith A	32	-	0.0%	93.5%	0.3%	N/A						
20	Oil							-	-	-	-	N/A	N/A
21	Scherer 3 ⁽²⁾	215	50,983	32.9%	92.9%	10.6%	10,978						
22	Coal								8,539	559,691	1,545,871	3.03	N/A
23	Oil							-	-	-	-		
24	Other Generation		5,528										
25	Gas										152,193		
26	Perdido		2,031										
27	Landfill Gas										78,157		
28	Blue Indigo		16,424										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	137,504	76.1%	92.3%	1.9%	10,194						
31	Coal							77,316	9,065	1,401,767	3,817,563	2.78	49.38
32	Oil-S							-	-	-	-		
33	Daniel 2 ⁽³⁾	251	-	0.0%	60.5%	0.0%	N/A						
34	Coal							-	-	-	-	N/A	N/A
35	Oil-S							-	-	-	-		
36	Gas,BL												
37	Gas							-	-	-	-	N/A	N/A
38	Ltr. Oil												
39	Oil							376	139,400	2,202	29,851	N/A	79.39
40	Total	2,376	894,817	52.3%	89.4%	40.9%	8,680			7,767,030	27,006,627	3.02	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
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Recoverable Fuel 27,006,627 3.02

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: OCTOBER 2021**

**Schedule E-4
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		0.0%	92.4%	0.0%	N/A						
2	Gas-G		-					-	-	-	73,296	0	N/A
3	Gas-S							-	-	-	-		N/A
4	Oil-S							-	-	-	-		N/A
5	GCEC 5 ⁽⁴⁾	78		0.0%	92.4%	0.0%	N/A						
6	Gas-G		-					-	-	-	73,296	0	N/A
7	Gas-S							-	-	-	-		N/A
8	Oil-S							-	-	-	-		N/A
9	GCEC 6 ⁽⁴⁾	315		2.9%	92.4%	0.0%	11,423						
10	Gas-G		6,720					75,260	1,020	76,765	319,105	4.75	4.24
11	Gas-S							-	-	-	-		N/A
12	Oil-S							-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	496		33.9%	92.4%	42.5%	11,772						
14	Gas-G		125,279					1,445,860	1,020	1,474,778	4,795,681	3.83	3.32
15	Gas-S							-	-	-	-		N/A
16	Oil-S							-	-	-	-		N/A
17	Smith 3	646	467,600	97.3%	93.5%	75.1%	6,890						
18	Gas-G							3,158,469	1,020	3,221,638	13,010,538	2.78	4.12
19	Smith A	40	-	0.0%	93.5%	0.3%	N/A						
20	Oil							-	-	-	-	N/A	N/A
21	Scherer 3 ⁽²⁾	215	-	0.0%	92.9%	6.1%	N/A						
22	Coal								-	-	-	N/A	N/A
23	Oil							-	-	-	-		
24	Other Generation		5,712										
25	Gas										157,259		
26	Perdido		2,097										
27	Landfill Gas										80,697		
28	Blue Indigo		15,891										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	131,174	70.2%	92.3%	0.0%	10,231						
31	Coal							74,349	9,025	1,342,016	3,629,622	2.77	48.82
32	Oil-S							-	-	-	-		
33	Daniel 2 ⁽³⁾	251	-	0.0%	60.5%	0.0%	N/A						
34	Coal							-	-	-	-	N/A	N/A
35	Oil-S							-	-	-	-		
36	Gas,BL												
37	Gas							-	-	-	-	N/A	N/A
38	Ltr. Oil												
39	Oil							309	139,400	1,807	24,018	N/A	77.73
40	Total	2,370	754,473	42.8%	89.4%	29.9%	8,108			6,117,004	22,163,512	2.94	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
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Recoverable Fuel 22,163,512 2.94

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: NOVEMBER 2021**

**Schedule E-4
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		0.0%	92.4%	0.0%	N/A						
2	Gas-G		-					-	-	-	70,931	0	N/A
3	Gas-S							-	-	-	-		N/A
4	Oil-S							-	-	-	-		N/A
5	GCEC 5 ⁽⁴⁾	78		0.0%	92.4%	0.0%	N/A						
6	Gas-G		-					-	-	-	70,931	0	N/A
7	Gas-S							-	-	-	-		N/A
8	Oil-S							-	-	-	-		N/A
9	GCEC 6 ⁽⁴⁾	315		41.9%	92.4%	20.2%	11,424						
10	Gas-G		95,059					1,064,615	1,020	1,085,908	3,607,407	3.79	3.39
11	Gas-S							-	-	-	-		N/A
12	Oil-S							-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	496		2.1%	92.4%	10.1%	11,772						
14	Gas-G		7,560					87,250	1,020	88,995	360,762	4.77	4.13
15	Gas-S							-	-	-	-		N/A
16	Oil-S							-	-	-	-		N/A
17	Smith 3	646	447,100	96.1%	63.5%	84.8%	6,871						
18	Gas-G							3,011,694	1,020	3,071,928	11,310,064	2.53	3.76
19	Smith A	40	-	0.0%	93.5%	0.0%	N/A						
20	Oil							-	-	-	-	N/A	N/A
21	Scherer 3 ⁽²⁾	215	-	0.0%	92.9%	0.0%	N/A						
22	Coal								-	-	-	N/A	N/A
23	Oil							-	-	-	-		
24	Other Generation		5,528										
25	Gas										152,193		
26	Perdido		2,031										
27	Landfill Gas										78,157		
28	Blue Indigo		12,454										
29	Solar										-		
30	Daniel 1 ⁽³⁾	251	50,137	27.7%	92.3%	2.4%	10,279						
31	Coal							28,645	8,996	515,369	1,386,739	2.77	48.41
32	Oil-S							-	-	-	-		
33	Daniel 2 ⁽³⁾	251	100,978	55.9%	60.5%	21.0%	10,334						
34	Coal							58,001	8,996	1,043,535	2,807,915	2.78	48.41
35	Oil-S							-	-	-	-		
36	Gas,BL												
37	Gas							-	-	-	-	N/A	N/A
38	Ltr. Oil												
39	Oil							762	139,400	4,464	60,938	N/A	79.97
40	Total	2,370	720,847	42.2%	81.2%	30.4%	8,060			5,810,199	19,906,037	2.76	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
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Recoverable Fuel 19,906,037 2.76

**GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: DECEMBER 2021**

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		0.0%	92.4%	0.0%	N/A						
2	Gas-G		-					-	-	-	73,296	0	N/A
3	Gas-S							-	-	-	-		N/A
4	Oil-S							-	-	-	-		N/A
5	GCEC 5 ⁽⁴⁾	78		0.0%	92.4%	0.0%	N/A						
6	Gas-G		-					-	-	-	73,296	0	N/A
7	Gas-S							-	-	-	-		N/A
8	Oil-S							-	-	-	-		N/A
9	GCEC 6 ⁽⁴⁾	315		31.2%	92.4%	30.6%	11,424						
10	Gas-G		73,079					818,453	1,020	834,822	2,880,634	3.94	3.52
11	Gas-S							-	-	-	-		N/A
12	Oil-S							-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	496		10.9%	92.4%	30.6%	11,772						
14	Gas-G		40,140					463,257	1,020	472,522	1,662,293	4.14	3.59
15	Gas-S							-	-	-	-		N/A
16	Oil-S							-	-	-	-		N/A
17	GCEC 8 ⁽⁴⁾	950		1.0%	92.4%	30.6%	9,936						
18	Gas-G		7,100					69,163	1,020	70,546	237,231	3.34	3.43
19	Gas-S							-	-	-	-		N/A
20	Oil-S							-	-	-	-		N/A
21	Smith 3	646	309,700	64.4%	93.5%	91.9%	6,847						
22	Gas-G							2,078,987	1,020	2,120,567	8,285,178	2.68	3.99
23	Smith A	40	-	0.0%	93.5%	0.0%	N/A						
24	Oil							-	-	-	-	N/A	N/A
25	Scherer 3 ⁽²⁾	215	-	0.0%	92.9%	0.0%	N/A						
26	Coal								-	-	-	N/A	N/A
27	Oil							-	-	-	-		
28	Other Generation		5,712										
29	Gas										157,259		
30	Perdido		2,097										
31	Landfill Gas										80,697		
32	Blue Indigo		9,851										
33	Solar										-		
34	Daniel 1 ⁽³⁾	251	131,840	70.6%	92.3%	3.6%	10,171						
35	Coal							74,738	8,971	1,340,947	3,592,412	2.72	48.07
36	Oil-S							-	-	-	-		
37	Daniel 2 ⁽³⁾	251	131,047	70.2%	60.5%	23.9%	10,014						
38	Coal							73,141	8,971	1,312,302	3,515,672	2.68	48.07
39	Oil-S							-	-	-	-		
40	Gas,BL												
41	Gas							-	-	-	-	N/A	N/A
42	Ltr. Oil												
43	Oil							762	139,400	4,464	62,160	N/A	81.57
44	Total	3,320	710,566	28.8%	90.2%	36.2%	8,664			6,156,170	20,620,128	2.90	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Adj. Units	Adj Description	Adj \$	cents/kWh
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Recoverable Fuel 20,620,128 2.90

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Plant/Unit & Fuel Type	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Burned Units (Tons/MCF/Bbl)	Fuel Heat Value (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost (\$)	Fuel Cost/kWh (¢/kWh)	Fuel Cost/Unit (\$/Unit)
1	GCEC 4 ⁽⁴⁾	78		7.0%	94.6%	0.1%	13,930						
2	Gas-G		47,586					649,471	1,021	662,865	2,567,033	5.39	3.95
3	Gas-S		-					3,820	1,027	3,923	15,954		4.18
4	Oil-S		-					116	139,163	678	6,290		54.22
5	GCEC 5 ⁽⁴⁾	78		2.4%	94.2%	9.0%	36,635						
6	Gas-G		16,301					587,352	1,017	597,182	2,364,954	14.51	4.03
7	Gas-S		-					72,212	1,015	73,272	237,337		3.29
8	Oil-S		-					81	135,215	460	4,343		53.62
9	GCEC 6 ⁽⁴⁾	312		30.8%	82.9%	36.0%	11,655	-	-	-	-		
10	Gas-G		840,524					9,575,304	1,023	9,796,622	33,771,237	4.02	3.53
11	Gas-S		-					8,360	1,025	8,565	32,128		3.84
12	Oil-S		-					-	-	-	-		N/A
13	GCEC 7 ⁽⁴⁾	493		23.9%	83.3%	42.4%	11,443	-	-	-	-		
14	Gas-G		1,031,873					11,541,606	1,023	11,807,685	40,583,377	3.93	3.52
15	Gas-S		-					6,067	1,025	6,221	22,825		3.76
16	Oil-S		-					-	-	-	-		N/A
17	GCEC 8 ⁽⁴⁾	950		1.0%	92.4%	92.4%	9,936						
18	Gas-G		7,100					69,163	1,020	70,546	237,231	3.34	3.43
19	Gas-S		-					-	-	-	-		N/A
20	Oil-S		-					-	-	-	-		N/A
21	Smith 3	682	4,998,590	83.7%	90.5%	80.2%	6,925						
22	Gas-G							33,817,188	1,024	34,612,889	128,585,556	2.57	3.80
23	Smith A	31	59	0.0%	86.3%	17.5%	32,898						
24	Oil-G							334	138,366	1,941	29,499	50.00	88.32
25	Scherer 3 ⁽²⁾	251	313,030	14.2%	92.7%	28.4%	11,223						
26	Coal									3,513,220	9,961,848	3.18	N/A
27	Oil							1,109		6,453	99,887		
28	Other Generation		79,569										
29	Gas										2,190,626		
30	Perdido		24,460										
31	Landfill Gas										941,329		
32	Blue Indigo		175,841										
33	Solar										-		
34	Daniel 1 ⁽³⁾	230	1,230,368	61.1%	78.8%	33.4%	10,425						
35	Coal							716,476	8,952	12,827,098	34,766,598	2.83	48.52
36	Oil-S							1,957	138,319	11,369	137,860		
37	Daniel 2 ⁽³⁾	230	503,124	25.0%	50.9%	19.4%	10,783						
38	Coal							304,813	8,899	5,424,992	14,727,725	2.93	48.32
39	Oil-S							75,958	2,219	7,078	80,896		
40	Gas,BL												
41	Gas							-	-	-	-	N/A	N/A
42	Ltr. Oil												
43	Oil							2,961	139,440	17,341	235,495	N/A	79.53
44	Total	3,335	9,268,425	31.7%	86.0%	58.5%	8,669	57,434,348		79,450,401	271,600,027	2.93	

Notes:

- (1) Smith A uses lighter oil
(2) Represents Gulf's 25% Ownership
(3) Represents Gulf's 50% Ownership

Total may not add due to rounding

Adj. Units	Adj Description	Adj \$	cents/kWh
	Daniel Railcar Track Depr	(41,967)	
(134,700)	Scherer Inv Adjustment - Coal	(375,303)	
	Crist Coal inventory adjustment	2,827,530	
	Crist other fuel Inventory Adjustmen	448,419	
	Daniel coal inventory adjustment	(237,629.19)	
Recoverable Fuel		274,221,076	2.96

GULF POWER COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1) Line No.	(2) Description	(3) January Actual	(4) February Actual	(5) March Actual	(6) April Actual	(7) May Actual	(8) June Actual	(9) July Estimated	(10) August Estimated	(11) September Estimated	(12) October Estimated	(13) November Estimated	(14) December Estimated	(15) 12 Month Period
LIGHT OIL														
1	PURCHASES :													
2	UNITS (BBL)	42	1,918	701	24	745	1,047	42	333	379	323	770	769	7,093
3	UNIT COST (\$/BBL)	343.14	77.97	88.68	559.46	94.39	96.54	92.12	87.83	87.75	86.82	86.70	86.59	90.05
4	AMOUNT (\$)	14,412	149,550	62,166	13,427	70,317	101,077	3,869	29,248	33,258	28,043	66,758	66,589	638,714
5	BURNED :													
6	UNITS (BBL)	470	1,799	635	199	1,052	387	376	376	376	309	762	762	7,504
7	UNIT COST (\$/BBL)	62.80	70.65	68.98	70.11	80.50	93.75	77.31	78.30	79.37	77.82	79.93	81.53	76.07
8	AMOUNT (\$)	29,515	127,104	43,804	13,951	84,690	36,280	29,076	29,452	29,851	24,018	60,938	62,160	570,839
9	ENDING INVENTORY :													
10	UNITS (BBL)	7,289	7,408	7,473	7,299	6,991	7,652	7,318	7,275	7,278	7,292	7,300	7,306	
11	UNIT COST (\$/BBL)	61.96	63.99	65.89	67.39	68.30	70.87	70.66	71.05	71.49	71.91	72.63	73.17	
12	AMOUNT (\$)	451,604	474,050	492,412	491,888	477,515	542,312	517,105	516,901	520,308	524,333	530,153	534,582	
COAL EXCLUDING PLANT SCHERER														
13	PURCHASES :													
14	UNITS (TONS)	71,681	39,477	55,657	87,807	139,815	79,768	74,000	76,000	87,500	87,500	87,500	100,000	986,705
15	UNIT COST (\$/TON)	43.28	48.91	45.72	46.15	45.38	50.18	55.65	55.42	47.08	47.08	47.08	47.08	48.01
16	AMOUNT (\$)	3,102,436	1,930,623	2,544,503	4,052,459	6,345,173	4,002,823	4,117,772	4,211,930	4,119,443	4,119,443	4,119,443	4,707,935	47,373,983
17	BURNED :													
18	UNITS (TONS)	93,432	79,999	78,184	97,514	54,648	67,706	81,888	81,728	77,316	74,349	86,646	147,879	1,021,289
19	UNIT COST (\$/TON)	48.32	48.91	48.27	47.62	46.67	47.46	48.65	50.14	49.38	48.82	48.41	48.07	48.41
20	AMOUNT (\$)	4,514,974	3,912,623	3,773,677	4,643,361	2,550,261	3,213,277	3,983,565	4,097,941	3,817,564	3,629,622	4,194,654	7,108,085	49,439,604
21	ENDING INVENTORY :													
22	UNITS (TONS)	261,501	220,979	198,452	188,745	273,912	285,974	278,086	272,358	282,542	295,693	296,547	248,668	
23	UNIT COST (\$/TON)	48.91	48.91	48.27	47.62	46.67	47.46	49.29	50.74	49.98	49.42	49.02	48.81	
24	AMOUNT (\$)	12,789,630	10,807,630	9,578,457	8,987,555	12,782,467	13,572,013	13,706,220	13,820,209	14,122,088	14,611,909	14,536,698	12,136,548	

GULF POWER COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
COAL at Plant Scherer ⁽¹⁾														
1	PURCHASES :													
2	UNITS (MMBTU)	469,650	(690,447)	1,117,553	647,595	(1,613,562)	(634,529)	447,608	414,890	441,395	537,579	419,720	461,080	2,018,532
3	UNIT COST (\$/MMBTU)	2.71	2.69	2.86	3.30	2.58	2.45	2.74	2.74	2.74	2.74	2.74	2.74	3.23
4	AMOUNT (\$)	1,274,249	(1,854,014)	3,201,017	2,136,644	(4,158,041)	(1,556,318)	1,227,671	1,137,811	1,210,957	1,474,211	1,150,678	1,265,025	6,509,889
5	BURNED :													
6	UNITS (MMBTU)	55,602	368,490	2,594	76,504	157,130	538,028	946,217	943,664	559,691	0	0	0	3,647,920
7	UNIT COST (\$/MMBTU)	2.79	2.80	2.80	2.79	3	3.16	2.77	2.76	2.76	#N/A	#N/A	#N/A	2.83
8	AMOUNT (\$)	154,910	1,030,156	7,252	213,141	459,962	1,700,469	2,617,129	2,608,261	1,545,871	0	0	0	10,337,151
9	ENDING INVENTORY :													
10	UNITS (MMBTU)	4,230,033	3,171,096	4,291,243	5,015,342	3,244,650	2,072,093	1,573,484	1,044,710	926,414	1,463,993	1,883,713	2,344,793	
11	UNIT COST (\$/MMBTU)	2.78	2.80	2.81	2.88	3.02	3.16	3.28	3.53	3.62	3.30	3.17	3.09	
12	AMOUNT (\$)	11,750,391	8,866,222	12,074,491	14,424,276	9,806,273	6,549,486	5,160,028	3,689,578	3,354,664	4,828,875	5,979,553	7,244,578	
GAS (Reported on a MMBTU and \$ basis)														
13	BURNED :													
14	UNITS (MMBTU)	5,621,881	5,736,867	4,052,271	1,904,393	3,726,448	4,746,236	6,604,362	6,510,493	5,803,370	4,773,181	4,246,831	3,498,457	57,224,790
15	UNIT COST (\$/MMBTU)	2.86	4.06	3.17	3.19	3.71	3.82	3.63	3.66	3.68	3.83	3.63	3.71	3.60
16	AMOUNT (\$)	16,078,377	23,272,618	12,842,649	6,079,501	13,842,112	18,113,284	23,978,523	23,813,384	21,382,992	18,271,916	15,420,095	12,974,697	206,070,148
OTHER - C.T. OIL														
17	PURCHASES :													
18	UNITS (BBL)	49	(90)	(12)	(8)	(15)	5,816	33,000	33,000	33,000	26,178	0	0	130,918
19	UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	95.19	96.06	96.18	96.30	96.37	0.00	0.00	96.23
20	AMOUNT (\$)	0	0	0	0	0	553,617	3,170,068	3,173,954	3,177,840	2,522,784	0	0	12,598,263
21	BURNED :													
22	UNITS (BBL)	0	45	0	214	0	75	0	0	0	0	0	0	334
23	UNIT COST (\$/BBL)	0.00	88.07	0.00	88.29	0.00	88.55	0.00	0.00	0.00	0.00	0.00	0.00	88.32
24	AMOUNT (\$)	0	3,963	0	18,895	0	6,641	0	0	0	0	0	0	29,499
25	ENDING INVENTORY :													
26	UNITS (BBL)	7,636	7,501	7,489	7,267	7,252	12,993	45,993	78,993	111,993	138,171	138,171	138,171	
27	UNIT COST (\$/BBL)	87.02	88.06	88.20	88.29	88.47	91.48	94.77	95.36	95.63	95.77	95.77	95.77	
28	AMOUNT (\$)	664,469	660,507	660,507	641,612	641,612	1,188,587	4,358,655	7,532,609	10,710,449	13,233,233	13,233,233	13,233,233	

(1) Includes Gulf's 100% ownership in Scherer Unit 3.

Schedule E-6
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POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Month	Type	Total KWH Sold	KWH From Own Generation	¢ / kWh		Total \$ for Fuel Adjustment	Total Cost (\$)
					Fuel Costs	Total Costs		
JANUARY								
1		Other Power Sales	469,611,185	469,611,185	2.27	0.88	10,674,187	4,123,323
2		Economy Sales	4,906,055	4,906,055	2.05	2.82	100,485	138,228
3		Gain on Economy Sales	0	0	0.00	0.00	10,141	10,141
4		TOTAL ACTUAL SALES	474,517,240	474,517,240	2.27	0.90	10,784,813	4,271,692
FEBRUARY								
5		Other Power Sales	353,394,429	353,394,429	3.27	3.59	11,569,148	12,693,992
6		Economy Sales	8,937,224	8,937,224	5.08	9.49	454,085	848,344
7		Gain on Economy Sales	0	0	0.00	0.00	338,682	346,614
8		TOTAL ACTUAL SALES	362,331,653	362,331,653	3.41	3.83	12,361,915	13,888,949
MARCH								
9		Other Power Sales	404,730,230	404,730,230	2.04	2.30	8,275,912	9,291,353
10		Economy Sales	6,408,723	6,408,723	2.07	2.96	132,621	189,810
11		Gain on Economy Sales	0	0	0.00	0.00	(7,251)	(9,064)
12		TOTAL ACTUAL SALES	411,138,953	411,138,953	2.04	2.30	8,401,282	9,472,099
APRIL								
13		Other Power Sales	56,180,166	56,180,166	2.27	2.52	1,274,210	1,414,427
14		Economy Sales	5,684,815	5,684,815	2.38	3.16	135,567	179,466
15		Gain on Economy Sales	0	0	0.00	0.00	15,473	19,341
16		TOTAL ACTUAL SALES	61,864,981	61,864,981	2.30	2.61	1,425,250	1,613,234
MAY								
17		Other Power Sales	84,080,425	84,080,425	2.96	36.07	2,492,580	30,324,474
18		Economy Sales	4,650,070	4,650,070	2.50	31.84	116,031	1,480,358
19		Gain on Economy Sales	0	0	0.00	0.00	16,594	387,774
20		TOTAL ACTUAL SALES	88,730,495	88,730,495	2.96	36.28	2,625,205	32,192,606
JUNE								
21		Other Power Sales	130,658,793	130,658,793	3.64	3.92	4,755,218	5,120,263
22		Economy Sales	4,130,976	4,130,976	3.38	4.60	139,641	190,185
23		Gain on Economy Sales	0	0	0.00	0.00	11,664	14,580
24		TOTAL ACTUAL SALES	134,789,769	134,789,769	3.64	3.95	4,906,523	5,325,028

Schedule E-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Month	Type	Total KWH Sold	KWH From Own Generation	¢ / kWh		Total \$ for Fuel Adjustment	Total Cost (\$)
					Fuel Costs	Total Costs		
JULY								
1		Other Power Sales	425,373,000	425,373,000	2.77	3.15	11,794,219	13,393,364
2		Economy Sales	7,253,000	7,253,000	3.59	3.90	260,425	282,816
3		Gain on Economy Sales	0	0	0.00	0.00	0	0
4		TOTAL ESTIMATED SALES	432,626,000	432,626,000	2.79	3.16	12,054,644	13,676,180
AUGUST								
5		Other Power Sales	442,945,000	442,945,000	2.77	3.14	12,287,875	13,888,195
6		Economy Sales	6,735,000	6,735,000	3.33	3.61	223,949	243,299
7		Gain on Economy Sales	0	0	0.00	0.00	0	0
8		TOTAL ESTIMATED SALES	449,680,000	449,680,000	2.78	3.14	12,511,824	14,131,494
SEPTEMBER								
9		Other Power Sales	472,358,000	472,358,000	2.64	3.00	12,490,596	14,173,742
10		Economy Sales	10,002,000	10,002,000	3.27	3.59	327,522	358,846
11		Gain on Economy Sales	0	0	0.00	0.00	0	0
12		TOTAL ESTIMATED SALES	482,360,000	482,360,000	2.66	3.01	12,818,118	14,532,588
OCTOBER								
13		Other Power Sales	183,568,000	183,568,000	2.30	2.61	4,217,857	4,788,364
14		Economy Sales	7,723,000	7,723,000	2.60	2.98	200,776	229,928
15		Gain on Economy Sales	0	0	0.00	0.00	0	0
16		TOTAL ESTIMATED SALES	191,291,000	191,291,000	2.31	2.62	4,418,633	5,018,292
NOVEMBER								
17		Other Power Sales	432,373,000	432,373,000	2.30	2.63	9,923,885	11,392,337
18		Economy Sales	5,719,000	5,719,000	2.43	2.78	139,100	158,882
19		Gain on Economy Sales	0	0	0.00	0.00	0	0
20		TOTAL ESTIMATED SALES	438,092,000	438,092,000	2.30	2.64	10,062,985	11,551,219
DECEMBER								
21		Other Power Sales	338,158,000	338,158,000	2.43	2.85	8,223,699	9,627,323
22		Economy Sales	3,272,000	3,272,000	2.55	2.99	83,576	97,739
23		Gain on Economy Sales	0	0	0.00	0.00	0	0
24		TOTAL ESTIMATED SALES	341,430,000	341,430,000	2.43	2.85	8,307,275	9,725,062
TOTAL								
25		Other Power Sales	3,793,430,228	3,793,430,228	2.58	3.43	97,979,386	130,231,157
26		Economy Sales	75,421,863	75,421,863	3.07	5.83	2,313,778	4,397,901
27		Gain on Economy Sales	0	0	0.00	0.00	385,303	769,386
28		TOTAL ESTIMATED SALES	3,868,852,091	3,868,852,091	2.60	3.50	100,678,466	135,398,444

Totals may not add due to rounding

Schedule E-7

**GULF POWER COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Month	Purchased From	Type & Schedule	Total KWH Purchased	KWH for Other	KWH for Interruptible	KWH for Firm	¢ / kWh Fuel Cost	Total Cost	Total \$ for Fuel Adj
1	January	NONE								
2	February	NONE								
3	March	NONE								
4	April	NONE								
5	May	NONE								
6	June	NONE								
7	July	NONE								
8	August	NONE								
9	September	NONE								
10	October	NONE								
11	November	NONE								
12	December	NONE								
13	Total	NONE								

Schedule E-8

GULF POWER COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Month	Purchased From	Type & Schedule	Total KWH Purchased	KWH for Other Utilities	KWH for Interruptible	KWH for Firm	¢ / kWh Fuel Cost	Total Cost	Total \$ for Fuel Adj
1	JANUARY	Total		9,604,991			None	2.52	0.00	241,981
2	FEBRUARY	Total		7,448,095			None	3.86	0.00	287,253
3	MARCH	Total		8,161,778			None	2.28	0.00	186,301
4	APRIL	Total		11,635,350			None	2.61	0.00	303,835
5	MAY	Total		9,963,627			None	2.80	0.00	279,402
6	JUNE	Total		13,005,108			None	3.38	0.00	439,569
7	JULY	Total		0			None	0.00	0.00	0
8	AUGUST	Total		0			None	0.00	0.00	0
9	SEPTEMBER	Total		0			None	0.00	0.00	0
10	OCTOBER	Total		0			None	0.00	0.00	0
11	NOVEMBER	Total		0			None	0.00	0.00	0
12	DECEMBER	Total		0			None	0.00	0.00	0
13	TOTAL			<u>59,818,949</u>				<u>2.91</u>	<u>0.00</u>	<u>1,738,340</u>

Schedule E-9
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ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Month	Type & Schedule	Total KWH Purchased	Transaction Cost ¢ / kWh	Total \$ for Fuel Adj.
JANUARY					
1		Southern Co. Interchange	10,122,839	1.90	191,987
2		Economy Purchases	5,160,768	3.45	177,977
3		Other Purchases	512,400,342	2.99	15,308,319
4		TOTAL ACTUAL PURCHASES	527,683,949	2.97	15,678,283
FEBRUARY					
5		Southern Co. Interchange	10,368,966	4.95	513,009
6		Economy Purchases	5,389,186	4.03	216,992
7		Other Purchases	372,645,481	3.74	13,930,906
8		TOTAL ACTUAL PURCHASES	388,403,633	3.77	14,660,907
MARCH					
9		Southern Co. Interchange	6,625,213	2.29	151,444
10		Economy Purchases	3,729,064	2.97	110,695
11		Other Purchases	521,558,477	3.28	17,118,464
12		TOTAL ACTUAL PURCHASES	531,912,754	3.27	17,380,603
APRIL					
13		Southern Co. Interchange	194,461,329	2.79	5,432,171
14		Economy Purchases	4,878,544	2.95	143,828
15		Other Purchases	193,005,931	4.10	7,919,942
16		TOTAL ACTUAL PURCHASES	392,345,804	3.44	13,495,941
MAY					
17		Southern Co. Interchange	158,649,997	2.84	4,511,820
18		Economy Purchases	6,217,584	3.06	190,259
19		Other Purchases	266,769,813	3.86	10,286,337
20		TOTAL ACTUAL PURCHASES	431,637,394	3.47	14,988,416
JUNE					
21		Southern Co. Interchange	27,925,797	3.05	851,969
22		Economy Purchases	1,968,634	3.45	67,872
23		Other Purchases	492,497,233	3.57	17,604,081
24		TOTAL ACTUAL PURCHASES	522,391,664	3.55	18,523,922

Schedule E-9
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ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Month	Type & Schedule	Total KWH Purchased	Transaction Cost ¢ / kWh	Total \$ for Fuel Adj.
JULY					
1		Southern Co. Interchange	2,645,000	4.36	115,402
2		Economy Purchases	1,510,000	3.44	51,987
3		Other Purchases	650,005,000	3.15	20,494,000
4		TOTAL ESTIMATED PURCHASES	654,160,000	3.16	20,661,389
AUGUST					
5		Southern Co. Interchange	3,495,000	4.09	142,968
6		Economy Purchases	1,700,000	3.42	58,133
7		Other Purchases	684,033,000	3.16	21,632,000
8		TOTAL ESTIMATED PURCHASES	689,228,000	3.17	21,833,101
SEPTEMBER					
9		Southern Co. Interchange	13,333,000	2.82	375,789
10		Economy Purchases	2,704,000	3.35	90,568
11		Other Purchases	732,847,000	3.16	23,191,000
12		TOTAL ESTIMATED PURCHASES	748,884,000	3.16	23,657,357
OCTOBER					
13		Southern Co. Interchange	86,197,000	2.96	2,547,644
14		Economy Purchases	2,435,000	3.30	80,399
15		Other Purchases	326,017,000	3.82	12,464,000
16		TOTAL ESTIMATED PURCHASES	414,649,000	3.64	15,092,043
NOVEMBER					
17		Southern Co. Interchange	12,795,000	2.57	328,362
18		Economy Purchases	1,141,000	2.97	33,883
19		Other Purchases	531,660,000	3.41	18,117,000
20		TOTAL ESTIMATED PURCHASES	545,596,000	3.39	18,479,244
DECEMBER					
21		Southern Co. Interchange	9,844,000	2.65	260,417
22		Economy Purchases	1,102,000	3.19	35,206
23		Other Purchases	476,165,000	3.34	15,892,000
24		TOTAL ESTIMATED PURCHASES	487,111,000	3.32	16,187,623
TOTAL FOR PERIOD					
25		Southern Co. Interchange	536,463,141	2.87	15,422,982
26		Economy Purchases	37,935,780	3.32	1,257,799
27		Other Purchases	5,759,604,277	3.37	193,958,049
28		TOTAL ACT/EST PURCHASES	6,334,003,198	3.33	210,638,829

Totals may not add due to rounding

Schedule CCE-1E

**GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP**

TO BE INCLUDED IN THE PERIOD JANUARY 2022 - DECEMBER 2022

Line No.	Description	Total
1	Estimated over/(under)-recovery, January 2021 - December 2021 (Schedule CCE-1B, line 15 + 18)	\$ 1,687,693
2	Final over/(under)-recovery, January 2020 - December 2020 (Exhibit RLH-1, Schedule CCA-1, line 3)	<u>838,127</u>
3	Total Over/(Under)-Recovery (Line 1 + 2) (To be included in January 2022 - December 2022)	<u>\$ 2,525,820</u>
4	Jurisdictional kWh sales, January 2022 - December 2022	<u>10,846,144,000</u>
5	True-up Factor (Line 3 / Line 4) x 100 (¢/kWh)	<u>(0.0233)</u>

**Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021**

	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1 IIC Payments/(Receipts) (\$)	22,530	(274,033)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(282,471)
2 Other Capacity Payments / (Receipts)	7,020,173	7,020,173	7,016,331	7,020,173	6,093,244	7,020,173	7,133,669	7,133,669	7,133,669	7,133,669	7,133,669	7,133,669	83,992,285
3 Transmission Revenue	(598)	(605)	(1,563)	(620)	(574)	(633)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(10,594)
4 Total Capacity Payments/(Receipts)	7,042,106	6,745,535	7,011,671	7,016,456	6,089,573	7,016,443	7,129,573	7,129,573	7,129,573	7,129,573	7,129,573	7,129,573	83,699,220
5 Jurisdictional Factor %	0.9759220	0.9759220	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	
a) Base Jurisdictional Factor			1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	
b) Intermediate Jurisdictional Factor			0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	
c) Peaking Jurisdictional Factor			0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	
d) Transmission Jurisdictional Factor			0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	
e) Total Base Jurisdictionalized Capacity Costs			(1,563)	(620)	(574)	(633)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	
f) Total Intermediate Jurisdictionalized Capacity Costs			6,847,392	6,851,142	5,946,531	6,851,142	6,961,905	6,961,905	6,961,905	6,961,905	6,961,905	6,961,905	
g) Total Peaking Jurisdictionalized Capacity Costs			(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	
h) Total Transmission Jurisdictionalized Capacity Costs													
6 Jurisdictional Capacity Payments/(Receipts) (Jan-Feb: Line 4 * 5; Mar-Dec: 5e+5f+5g) (\$)	6,872,546	6,583,116	6,843,473	6,848,165	5,943,601	6,848,152	6,958,549	6,958,549	6,958,549	6,958,549	6,958,549	6,958,549	81,690,344
7 Retail KWH Sales							1,144,418,000	1,154,359,000	1,080,505,000	909,722,000	765,774,000	785,575,000	
8 Purchased Power Capacity Cost Recovery Factor (\$/KWH)							0.800	0.800	0.800	0.800	0.800	0.800	
9 Capacity Cost Recovery Revenues (Line 7 x Line 8/100) (\$)	6,614,946	6,094,477	5,583,050	5,539,017	7,150,333	7,984,396	9,155,344	9,234,872	8,644,040	7,277,776	6,126,192	6,284,600	85,689,043
10 Revenue Taxes (Line 9 x .00072) (\$)	4,763	4,388	4,020	3,988	5,148	5,749	6,592	6,649	6,224	5,240	4,411	4,525	61,697
11 True-Up Provision (\$)	(187,311)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(2,247,743)
Capacity Cost Recovery Revenues net of Revenue Taxes (Line 9 - Line 10 + Line 11) (\$)	6,422,873	5,902,777	5,391,718	5,347,717	6,957,873	7,791,335	8,961,440	9,040,911	8,450,504	7,085,224	5,934,469	6,092,763	83,379,603
13 Over/(Under) Recovery (Line 12 - Line 6) (\$)	(449,673)	(680,339)	(1,451,755)	(1,500,448)	1,014,272	943,183	2,002,891	2,082,362	1,491,955	126,675	(1,024,080)	(865,786)	1,689,259
14 Interest Provision (\$)	(109)	(136)	(233)	(307)	(190)	(149)	(88)	61	193	260	243	192	(263)
15 Total Estimated True-Up for the Period January 2021 - December 2021 (Line 13 + Line 14) (\$)													1,688,996
16 Beginning Balance True-Up & Interest Provision (\$)	(1,409,616)	(1,672,087)	(2,165,250)	(3,431,228.79)	(4,744,672)	(3,543,277)	(2,412,931)	(222,816)	2,046,920	3,726,380	4,040,628	3,204,103	
17 True-Up Collected/(Refunded) (\$)	187,311	187,312	187,312	187,312	187,312	187,312	187,312	187,312	187,312	187,312	187,312	187,312	
18 Adjustment	0	0	(1,303)	0	0	0	0	0	0	0	0	0	(1,303)
19 End of Period TOTAL Net True-Up (Lines 13 + 14 + 16 + 17 + 18) (\$)	(1,672,087)	(2,165,250)	(3,431,229)	(4,744,672)	(3,543,277)	(2,412,931)	(222,816)	2,046,920	3,726,380	4,040,628	3,204,103	2,525,821	

SCHEDULE CCA-2

**GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2021 - DECEMBER 2021**

	January	February	March	April	May	June	July	August	September	October	November	December	Total
1. IIC Payments / (Receipts) (\$)	22,530	(274,033)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(3,097)	(282,471)
2. Other Capacity Payments / (Receipts)	7,020,173	7,020,173	7,016,331	7,020,173	6,093,244	7,020,173	7,133,669	7,133,669	7,133,669	7,133,669	7,133,669	7,133,669	83,992,285
3. Transmission Revenue (\$)	(598)	(605)	(1,563)	(620)	(574)	(633)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(10,594)
4. Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) (\$)	7,042,106	6,745,535	7,011,671	7,016,457	6,089,573	7,016,444	7,129,573	7,129,572	7,129,573	7,129,572	7,129,573	7,129,572	83,699,220
5. Jurisdictional %	0.9759220	0.9759220	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	
a) Base Jurisdictional Factor			1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	
b) Intermediate Jurisdictional Factor			0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	0.975922	
c) Peaking Jurisdictional Factor			0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	0.760860	
d) Transmission Jurisdictional Factor			0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	0.972343	
e) Total Base Jurisdictionalized Capacity Costs			(1,563)	(620)	(574.14)	(633.36)	(1,000.00)	(1,000.00)	(1,000.00)	(1,000.00)	(1,000.00)	(1,000.00)	
f) Total Intermediate Jurisdictionalized Capacity Costs			6,847,392	6,851,142	5,946,531	6,851,142	6,961,905	6,961,905	6,961,905	6,961,905	6,961,905	6,961,905	
g) Total Peaking Jurisdictionalized Capacity Costs			(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	(2,356)	
h) Total Transmission Jurisdictionalized Capacity Costs													
6. Total Jurisdictional Recovery Amount (Jan-Feb: Line 4 * 5; Mar-Dec: 5e+5f+5g) (\$)	6,872,546	6,583,116	6,843,473	6,848,165	5,943,601	6,848,152	6,958,549	6,958,549	6,958,549	6,958,549	6,958,549	6,958,549	81,690,344
7. Jurisdictional Capacity Cost Recovery Revenues Net of Taxes (\$)	6,610,184	6,090,089	5,579,030	5,535,029	7,145,185	7,978,647	9,148,752	9,228,223	8,637,816	7,272,536	6,121,781	6,280,075	85,627,348
8. True-Up Provision (\$)	(187,311)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(187,312)	(2,247,743)
9. Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) (\$)	6,422,873	5,902,777	5,391,718	5,347,717	6,957,873	7,791,335	8,961,440	9,040,911	8,450,504	7,085,224	5,934,469	6,092,763	83,379,604
10. Over/(Under) Recovery (Line 9 - 6) (\$)	(449,673)	(680,339)	(1,451,755)	(1,500,448)	1,014,272	943,183	2,002,891	2,082,362	1,491,955	126,675	(1,024,079)	(865,786)	1,689,260
11. Interest Provision (\$)	(109)	(136)	(233.23)	(306.58)	(190)	(149)	(88)	61	193	260	243	192	(263)
12. Beginning Balance True-Up & Interest Provision (\$)	(1,409,616)	(1,672,087)	(2,165,250)	(3,431,228.79)	(4,744,672)	(3,543,277)	(2,412,931)	(222,816)	2,046,920	3,726,380	4,040,628	3,204,104	(1,409,616)
13. True-Up Collected/(Refunded) (\$)	187,311	187,312	187,312	187,312	187,312	187,312	187,312	187,312	187,312	187,312	187,312	187,312	2,247,743
14. Adjustment	-	-	(1,303)	-	-	-	-	-	-	-	-	-	(1,303)
15. End of Period Total Net True-Up (Lines 10 + 11 + 12 + 13 + 14) (\$)	(1,672,087)	(2,165,250)	(3,431,228.79)	(4,744,671.50)	(3,543,277)	(2,412,931)	(222,816)	2,046,920	3,726,380	4,040,628	3,204,104	2,525,822	2,525,821

**GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2021 - DECEMBER 2021**

	Actual JANUARY	Actual FEBRUARY	Actual MARCH	Actual APRIL	Actual MAY	Actual JUNE	Estimated JULY	Estimated AUGUST	Estimated SEPTEMBER	Estimated OCTOBER	Estimated NOVEMBER	Estimated DECEMBER	TOTAL
1. Beginning True-Up Amount (\$)	(1,409,616)	(1,672,087)	(2,166,553.00)	(3,431,228.79)	(4,744,671.50)	(3,543,277.11)	(2,412,931.00)	(222,815.91)	2,046,919.58	3,726,380.36	4,040,627.93	3,204,104.01	
2. Ending True-Up Amount Before Interest (\$)	(1,671,978)	(2,165,114)	(3,432,298.56)	(4,744,364.92)	(3,543,087.18)	(2,412,782.10)	(222,727.62)	2,046,858.47	3,726,186.96	4,040,367.74	3,203,861.32	2,525,630.39	
3. Total Beginning & Ending True-Up Amount (\$) (Lines 1 + 2)	(3,081,594)	(3,837,201)	(5,598,851.56)	(8,175,593.71)	(8,287,758.68)	(5,956,059.21)	(2,635,658.62)	1,824,042.56	5,773,106.54	7,766,748.11	7,244,489.25	5,729,734.40	
4. Average True-Up Amount (\$)	(1,540,797)	(1,918,601)	(2,799,425.78)	(4,087,796.86)	(4,143,879.34)	(2,978,029.61)	(1,317,829.31)	912,021.28	2,886,553.27	3,883,374.05	3,622,244.62	2,864,867.20	
5. Interest Rate - First Day of Reporting Business Month	0.09%	0.08%	0.09%	0.11%	0.07%	0.04%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	
6. Interest Rate - First Day of Subsequent Business Month	0.08%	0.09%	0.11%	0.07%	0.04%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	
7. Total Interest Rate (Lines 5 + 6)	0.17%	0.17%	0.20%	0.18%	0.11%	0.12%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	
8. Average Interest Rate	0.085%	0.085%	0.100%	0.090%	0.055%	0.060%	0.080%	0.080%	0.080%	0.080%	0.080%	0.080%	
9. Monthly Average Interest Rate (1/12 Of Line 8)	0.0071%	0.0071%	0.0083%	0.0075%	0.0046%	0.0050%	0.0067%	0.0067%	0.0067%	0.0067%	0.0067%	0.0067%	
10. Interest Provision For the Month (Lines 4 X 9) (\$)	(109)	(136)	(233.23)	(306.58)	(189.93)	(148.90)	(88.29)	61.11	193.40	260.19	242.69	191.95	(263)

Gulf Power Company
2021 Capacity Contracts
ACTUAL FOR THE PERIOD JANUARY 2021 - JUNE 2021 / ESTIMATED FOR JULY 2021 - DECEMBER 2021

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Term		Contract Type										
	Start	End ⁽¹⁾											
1	Southern Intercompany Interchange		SES Opco										
2	<u>PPAs</u>												
3	Shell Energy N.A. (U.S.), LP		Firm										
4	<u>Other</u>												
5	South Carolina PSA		Other										
6	Rainbow Energy Marketing Corporation		Other										

Capacity Costs Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	TOTAL
7 Southern Intercompany Interchange													
8 <u>PPAs</u>													
9 Shell Energy N.A. (U.S.), LP													
10 <u>Other</u>													
11 South Carolina PSA													
12 Rainbow Energy Marketing Corporation													
13 Total	7,042,704	6,746,140	7,013,235	7,017,077	6,090,147	7,017,077	7,130,573	7,130,573	7,130,573	7,130,573	7,130,573	7,130,573	83,709,814

Capacity MW Description	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Projection	August Projection	September Projection	October Projection	November Projection	December Projection
14 Southern Intercompany Interchange	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15 <u>PPAs</u>												
16 Shell Energy N.A. (U.S.), LP												
17 <u>Other</u>												
18 South Carolina PSA												
19 Rainbow Energy Marketing Corporation												

20 (1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.

TOTAL GAINS SCHEDULE
Actual for the Period of: January 2020 through December 2020

TABLE 1

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Wholesale Sales Gains (\$)	Wholesale Purchases Savings (\$)	Asset Optimization Gains (\$)	Total Monthly Gains (\$)	Threshold 1 Gains ≤ \$30M (\$)	Threshold 2 \$30M > Gains ≤ \$40M (\$)	Threshold 3 \$40M > Gains ≤ \$100M (\$)	Threshold 4 Gains > \$100M (\$)
				(2)+(3)+(4)				
January	4,042,570	4,635	1,486,113	5,533,318	5,533,318	0	0	0
February	4,001,382	438	1,671,779	5,673,599	5,673,599	0	0	0
March	1,548,190	201,419	1,578,565	3,328,174	3,328,174	0	0	0
April	1,737,093	211,617	932,990	2,881,700	2,881,700	0	0	0
May	2,556,649	12,412	1,177,549	3,746,610	3,746,610	0	0	0
June	1,609,744	282,976	1,168,588	3,061,308	3,061,308	0	0	0
July	1,530,215	473,495	1,173,280	3,176,990	3,176,990	0	0	0
August	1,473,408	470,899	1,338,762	3,283,069	2,598,302	684,767	0	0
September	1,384,629	655,744	1,459,273	3,499,645	0	3,499,645	0	0
October	1,409,221	396,441	1,376,190	3,181,853	0	3,181,853	0	0
November	1,931,583	30,092	2,079,510	4,041,185	0	2,633,735	1,407,450	0
December	2,194,709	358	2,532,533	4,727,600	0	0	4,727,600	0
Total	25,419,391	2,740,526	17,975,132	46,135,050	30,000,000	10,000,000	6,135,050	0

TABLE 2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Threshold 1 Gains ≤ \$30M 100% Customer Benefit (\$)	Threshold 2 \$30M > Gains ≤ \$40M 100% Customer Benefit (\$)	Threshold 3 \$40M > Gains ≤ \$100M 40% Customer Benefit (\$)	Threshold 3 \$40M > Gains ≤ \$100M 60% FPL Benefit (\$)	Threshold 4 Gains > \$100M 50% Customer Benefit (\$)	Threshold 4 Gains > \$100M 50% FPL Benefit (\$)	Total Customer Benefits (\$)	Total FPL Benefits (\$)
January	5,533,318	0	0	0	0	0	5,533,318	0
February	5,673,599	0	0	0	0	0	5,673,599	0
March	3,328,174	0	0	0	0	0	3,328,174	0
April	2,881,700	0	0	0	0	0	2,881,700	0
May	3,746,610	0	0	0	0	0	3,746,610	0
June	3,061,308	0	0	0	0	0	3,061,308	0
July	3,176,990	0	0	0	0	0	3,176,990	0
August	2,598,302	684,767	0	0	0	0	3,283,069	0
September	0	3,499,645	0	0	0	0	3,499,645	0
October	0	3,181,853	0	0	0	0	3,181,853	0
November	0	2,633,735	562,980	844,470	0	0	3,196,715	844,470
December	0	0	1,891,040	2,836,560	0	0	1,891,040	2,836,560
Total	30,000,000	10,000,000	2,454,020	3,681,030	0	0	42,454,020	3,681,030

WHOLESALE POWER DETAIL
Actual for the Period of: January 2020 through December 2020

Wholesale Sales - Table 1						
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Month	Total Wholesale Sales (MWh)	OS Gross Gains (\$)	Third-Party Transmission Costs (\$)	Variable Power Plant O&M Costs (\$)	Power Option Premiums (\$)	Total Net Wholesale Sales Gains (\$)
	Schedule A6	Schedule A6	Schedule A6	Schedule A6	*CCRC	(3)+(4)+(5)+(6)
January	454,795	4,426,727	(88,540)	(295,617)	0	4,042,570
February	492,490	4,399,207	(77,707)	(320,119)	0	4,001,382
March	187,441	1,491,016	0	(121,837)	179,010	1,548,190
April	218,562	1,603,758	0	(142,065)	275,400	1,737,093
May	260,180	2,441,847	(661)	(169,117)	284,580	2,556,649
June	172,454	1,556,051	548	(112,095)	165,240	1,609,744
July	172,761	1,642,811	(301)	(112,295)	0	1,530,215
August	168,343	1,582,831	0	(109,423)	0	1,473,408
September	159,734	1,488,456	0	(103,827)	0	1,384,629
October	160,250	1,503,948	0	(104,163)	9,435	1,409,221
November	200,853	1,881,852	0	(130,554)	180,285	1,931,583
December	163,378	1,536,549	398,710	(106,196)	365,645	2,194,709
Total	2,811,241	25,555,054	232,049	(1,827,307)	1,459,595	25,419,391

Wholesale Purchases - Table 2					
(1)	(2)	(3)	(4)	(5)	(6)
Month	Total Wholesale Purchases (MWh)	OS Savings (\$)	Capacity Purchases (MWh)	Net Capacity Purchases Savings (\$)	Total Wholesale Purchases Savings (\$)
	Schedule A9	Schedule A9	Schedule A7/A12		(3) + (5)
January	960	4,635	0	0	4,635
February	90	438	0	0	438
March	34,724	201,419	0	0	201,419
April	19,783	211,617	0	0	211,617
May	2,072	12,412	0	0	12,412
June	41,543	282,976	0	0	282,976
July	50,743	473,495	0	0	473,495
August	13,348	470,899	0	0	470,899
September	36,650	655,744	0	0	655,744
October	56,265	396,441	0	0	396,441
November	2,004	30,092	0	0	30,092
December	80	358	0	0	358
Total	258,262	2,740,526	0	0	2,740,526

ASSET OPTIMIZATION DETAIL
Actual for the Period of: January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Month	Natural Gas Delivered City-Gate Sales (\$)	Natural Gas Production Area Sales (\$)	Natural Gas Capacity Release Firm Transport (\$)	Natural Gas Option Premiums (\$)	Delivered Natural Gas Savings (\$)	Natural Gas Storage Optimization (\$)	Natural Gas AMA Gains (\$)	OBA Service Gains (\$)	Electric Transmission Capacity Release Firm Transmission (\$)	NOX Emissions Sales (\$)	Total Asset Optimization Gains (\$)
January											
February											
March											
April											
May											
June											
July											
August											
September											
October											
November											
December											
Total	1,919,429	800,131	2,838,728	7,548,469	0	1,679,113	3,161,263	28,000	0	0	17,975,132

INCREMENTAL OPTIMIZATION COSTS
Actual for the Period of: January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Personnel Expenses (\$)	Other Expenses*	Wholesale Sales (MWh)	Wholesale Purchases (MWh)	Wholesale Sales VOM (\$)	Wholesale Purchases VOM (\$)	Net VOM (\$)	Total Incremental O&M Expenses (\$)
	Schedule A2						Schedule A2	(2) + (3) + (8)
January	46,772	0	454,795	960	295,617	624	294,993	341,764
February	43,406	0	492,490	90	320,119	59	320,060	363,466
March	46,420	0	187,441	34,724	121,837	22,571	99,266	145,687
April	30,338	15,112	218,562	19,783	142,065	12,859	129,206	174,656
May	33,911	10,075	260,180	2,072	169,117	1,347	167,770	211,756
June	40,611	6,121	172,454	41,543	112,095	27,003	85,092	131,824
July	42,357	158	172,761	50,743	112,295	32,983	79,312	121,826
August	37,656	0	168,343	13,348	109,423	8,676	100,747	138,403
September	39,292	0	159,734	36,650	103,827	23,823	80,005	119,297
October	41,653	0	160,250	56,265	104,163	36,572	67,590	109,244
November	37,427	0	200,853	2,004	130,554	1,303	129,252	166,679
December	41,016	0	163,378	80	106,196	52	106,144	147,159
Total	480,859	31,467	2,811,241	258,262	1,827,307	167,870	1,659,436	2,171,762

*Includes software and hardware expenses

FUEL COST RECOVERY
2022 RISK MANAGEMENT PLAN

GJY-2
DOCKET NO. 20210001-EI
FPL WITNESS: GERARD J. YUPP
EXHIBIT
JULY 27, 2021

2022 RISK MANAGEMENT PLAN

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Florida Power and Light Company

2022 Risk Management Plan

Florida Power & Light (“FPL”) recognizes the importance of managing price volatility in the fuel and power it purchases to provide electric service to its customers. Further, FPL recognizes that the greater the proportion of a particular energy source it relies upon to provide electric services to its customers, the greater the importance of managing price volatility associated with that energy source.

FPL’s risk management plan is based on the following guiding principles:

- a) A well-managed hedging program does not involve speculation or market timing. Its primary purpose is not to reduce FPL’s fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs over time.
- b) Hedging can result in significant lost opportunities for savings in the fuel costs to be paid by customers if fuel prices actually settle at lower levels than at the time the hedges were placed. FPL does not predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place.
- c) Market prices and forecasts of market prices have experienced significant volatility and are expected to continue to be highly volatile and, therefore, FPL does not intend to “outguess the market” in choosing the specific timing for effecting hedges or the percentage or volume of fuel hedged.
- d) In order to balance the goal of reducing customers’ exposure to rising fuel prices against the goal of allowing customers to benefit from falling fuel prices, it is appropriate to limit hedging to a portion of the total expected volume of fuel purchases.

Overall Quantitative and Qualitative Risk Management Objectives (TFB-4, Item 1)

FPL’s risk management objectives are to effectively execute a well-disciplined and independently controlled fuel hedging strategy to achieve the goal of fuel price stability (volatility minimization). FPL’s fuel hedging strategy aims to reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL’s customers.

Fuel Procurement Risks (TFB-4, Item 3)

FPL encounters several potential risks when executing its fuel procurement activities. These risks are grouped into four categories as detailed below:

Market Risk

Market Risk is the risk of changes in economic fair value due to fluctuations in market prices, volatility, correlation, and interest rates. Market risk has a direct impact on any open or unhedged energy positions.

Limits (“Limits”) are set by the President and Chief Executive Officer (“CEO”) of NextEra Energy (“NEE”) and delegated to the Exposure Management Committee (“EMC”). The EMC establishes a forum for discussion of NEE’s energy risk profile and operations and develops guidelines required for an appropriate risk management control infrastructure, which includes implementation and monitoring of compliance with the NextEra Energy Trading and Risk Management Policy (“Policy”). The EMC has in turn delegated limits to FPL Energy Marketing and Trading (“EMT”) for specific portfolios.

Limits (collectively referred to as “Limits”) are generally expressed in terms of:

- Maximum portfolio tenor; and
- Open (un-hedged) positions (where appropriate)

The FPL hedging program Limits will be managed in accordance with established corporate guidance. During the ordinary course of business, EMT management will have regard to these NEE Limits, such that pre-approval will be obtained before committing to transactions or contracts which might otherwise cause them to be breached. Adherence to Limits is monitored by the Risk Management Department.

Credit Risk

Credit risk management includes appropriate creditworthiness review and monitoring processes, the request for collateral if deemed necessary, and the inclusion of contractual risk mitigation terms and conditions whenever possible. Such credit risk mitigations include collateral threshold amounts, cross default amounts, payment netting, and set-off agreements. Credit Limits are typically established for trading transactions and are designed to manage counterparty credit risk; and set appropriate levels at which to trigger communication concerning risk and strategy.

During the ordinary course of business, EMT management adheres to these credit limits, such that pre-approval is obtained before committing to transactions or contracts which might otherwise cause the credit limits to be breached. Adherence to limits is monitored by the Risk Management Department, as well as dealmakers.

Liquidity Risk

Transacting Liquidity: The availability of market participants willing to transact or having credit quality to transact will have an impact on the utility’s ability to execute hedging and risk management strategies.

Short-Term Funding Liquidity: Changes in underlying market parameters may impact movements of cash in relation to business activities. Positions that are balanced for fair value purposes, but unbalanced for cash flow purposes, may give rise to large swings in cash balances. Risk Management assists the Finance Department by analyzing and monitoring the sufficiency of the allocated portions of the corporate facilities as they relate to EMT liquidity requirements.

Operational Risk

Operating risk is the physical risk associated with maintaining and operating generation assets. The potential risks that FPL encounters with its physical fuel procurement are fuel supply and transportation availability, product quality, delivery timing, weather, environmental, and supplier failure to deliver.

There is also operational risk specific to the wholesale trading activities, relating to inaccurate records of assets and transactions (“Administrative Operational Risk”). Certain personnel are authorized to transact on behalf of FPL and in so doing, can obligate the entity “instantaneously.” FPL maintains sufficient controls to ensure that information relating to commitments, obligations and assets are captured accurately, completely and on a timely basis.

Fuel Procurement Oversight/Policies and Procedures (TFB-4, Items 4, 5, 6, 7 and 9)

FPL provides its fuel procurement activities with independent oversight.

The President of FPL is responsible for authorizing all hedging activities. Changes in strategies and any deviations from the program are approved by the President of FPL or his designee prior to execution. Program activity is included in the Monthly Operations Performance Review (“MOPR”) chaired by the CEO of NEE. In addition, the EMC reviews performance and current procurement/hedging activities on a monthly basis.

The utility is supported by an independent middle office Risk Management department that provides oversight of fuel procurement activities. FPL has formal Policy and Procedures documents, signed by all employees, which include controls specifically related to the fuels hedging program. The Risk Management department ensures that the approved execution strategies are followed for each program. Daily and monthly reports are generated and reviewed by the Risk Management department and distributed to various groups, including executive management. Credit reviews are performed by the Risk Management department and included in the reporting mentioned above. Execution strategies must be approved prior to the execution of any transactions and documented as a Planned Position Strategy (“PPS”). All hedge transactions are to be addressed within this strategy document per the ranges and percentages defined in the Risk Management Plan and may be modified from time to time.

Policy and Procedures

As part of this Risk Management Plan, FPL is attaching the latest Policy and Trading and Risk Management Procedures Manual ("Procedures"). NEE updates the Policy and Procedures as necessary. For details that are not covered in this document, please refer to the Policy and Procedures. FPL considers its Policy and Procedures to be confidential.

The NEE corporate risk Policy delineates individual and group transaction limits and authorizations for all fuel procurement activities. The Policy sets out the NEE approach to energy risk and the management of risk, as follows:

- Identification and definition;
- Quantification and measurements;
- Reporting;
- Authority to transact; and
- Ownership and roles and responsibilities.

The Procedures Manual provides guidance that will promote efficient and accurate processing of transactions, effective preparation and distribution of information relating to trading and marketing activities, and efficient monitoring of the portfolio of risks, all within a well-controlled environment.

FPL's deal execution and capture functions coordinate activities across relevant departments, personnel, and systems. This framework of activity properly links the responsibilities of personnel and provides a sufficient medium to resolve issues.

The Procedures clearly list authorized trading personnel, trading limits, tenors, and acceptable instruments. Access to the data entry privileges in the deal capture system is limited to only those individuals who are formally granted permissions to enter trades. All transactions are entered and managed through a centralized deal capture system that supports routine reporting, settlements, and review. Transaction record editing is managed through acceptable authorizations and processes. Credit information is available to traders on a timely basis through daily reporting produced by the Risk Management department. Auditable records of all transactions are maintained and subject to review on a regular basis.

Deal Execution Details

FPL traders receive daily credit reports and credit watch lists from the Risk Management department to ensure that FPL does not enter into a trade with an unauthorized counterparty. FPL traders then select counterparties from this list to transact with as the hedging program is executed. FPL uses a market comparison approach to execute financial hedges. For natural gas, real-time prices can be observed by FPL through electronic tools, such as ICE ("InterContinental Exchange"), FutureSource, or over-the-counter brokers.

FPL traders generally execute trades with counterparties offering the best price for a given instrument. However, in a case where two or more counterparties are

offering similar pricing, the traders will attempt to execute trades with the counterparty that has the least amount of credit exposure with FPL. This is done primarily to allow FPL to spread its risk among as many counterparties as possible, but also affords the advantage of preventing the inadvertent telegraphing of FPL's commercial intentions to the market, thus helping to ensure favorable pricing for FPL's hedges.

2022 Hedging Strategy (TFB-4, Items 2 and 8)

FPL plans to hedge a portion of its projected 2023 natural gas requirements during 2022. Absent special circumstances (e.g. a hurricane that FPL concludes will substantially impair market functions); FPL will implement its hedging program within the following parameters:

- 1) FPL will hedge approximately [REDACTED] of its projected 2023 natural gas requirements from [REDACTED] through [REDACTED] ("the Hedging Window") using financial swaps, and/or physical fixed price transactions. FPL will hedge approximately [REDACTED] of each individual month's projected natural gas requirements. FPL will not financially hedge its projected natural gas requirements beyond the end of calendar year 2023.
- 2) During each month of the Hedging Window, FPL will hedge between [REDACTED] and [REDACTED] of the target monthly volumes. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.
- 3) FPL intends to rebalance its natural gas hedge positions during the year based on changes in forecasted market prices, projected unit outage schedules or changes in FPL's load forecast. Once the initial monthly target volumes have been hedged, rebalancing will be executed to maintain the hedge percentages inside approved tolerance bands. FPL will maintain an overall hedge percentage that falls within a [REDACTED] tolerance band. Therefore, the minimum and maximum monthly hedge percentages are [REDACTED] and [REDACTED] respectively.
- 4) FPL does not intend to hedge fuel oil for 2023.

Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)

FPL reporting systems comprehensively identify, measure, and monitor all forms of risk associated with fuel procurement activities.

FPL's philosophy on reporting is that it should be timely, consistent, flexible, and transparent. Timely and consistent reporting of risk information is critical to the effective management of risk. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, current and historical

pricing database, deal information, valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

Specifically, several reports are available at FPL to monitor risk:

Daily Management Report

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details the current Mark to Market (spot and forward), unrealized Mark to Market changes, and VaR. This report is published only after proper and thorough discussion between Risk Management and desk heads, if necessary for clarification, and resolution of any issues raised.

Credit Exposure Reporting

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details:

- Allowable deal types by counterparty
- Restrictions on counterparties

EMC Update

The Vice President Trading Risk Management provides a formal update to the EMC on a monthly basis. The agenda for the update will be agreed in advance with the EMC Chairman, but at a minimum contains the following items:

- Summary and explanation of significant changes in market risk and fair value;
- Summary and explanation of significant changes in credit risk;
- Exceptions to Risk Management Policy; and
- Minutes of previous EMC update for approval.

Hedge Program Limitations (TFB-4, Item 15)

FPL does not currently have any limitations on implementing certain hedging techniques that would provide a net benefit to customers.

Summary Update on Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) on Utility Hedgers

FPL's OTC financial derivatives are subject to rules implementing certain provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act and similar international rules. FPL has reviewed these rules and has implemented

policies and procedures to comply with those rules that affect its business. FPL's fuel hedging program is classified as bona-fide hedging under such rules and therefore, FPL will be able to transact swaps in the over-the-counter market without being subject to mandatory clearing or mandatory margin requirements. However, FPL will still be subject to any margin requirements that its counterparties require.

FPL cannot predict the impact that any proposed or not fully implemented final rules will have on its ability to hedge its commodity risks or on the OTC derivatives market as a whole, but such rules should not have a material effect on FPL's risk exposure. It is possible, however, that they may reduce market liquidity and increase the cost of hedging activities.

Energy Marketing & Trading
A division of
Florida Power & Light Company

Trading and Risk Management

Procedures Manual

|

Last Revision: ~~December 2020~~ July 2021

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 2 through 61]

EMT Trading and Risk Management Procedures as of July 21, 2021



NextEra Energy, Inc. Energy Trading and Risk Management Policy

APPROVED BY THE EMC ON:

Last approved on December 31, 2020

Last Updated December 2020

(See EMC Emails noting approval. Please contact Risk Management at 561-304-6028)



REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 2 through 26]

NEE Trading and Risk Management Policy

Florida Power and Light Company **2022 Risk Management Plan**

Overall Quantitative and Qualitative Risk Management Objectives (TFB-4, Item 1)

FPL's risk management objectives are to effectively execute a well-disciplined fuel procurement strategy to achieve the goal of securing adequate and reliable fuel supply to meet generation requirements, while minimizing overall fuel costs for FPL's customers.

Fuel Procurement Risks (TFB-4, Item 3)

FPL encounters several potential risks when executing its fuel procurement strategy. These risks are grouped into four categories as detailed below:

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FPL traders generally execute trades with counterparties offering the best price for a given instrument. However, in a case where two or more counterparties are offering similar pricing, the traders will attempt to execute trades with the counterparty that has the least amount of credit exposure with FPL. This is done primarily to allow FPL to spread its risk among as many counterparties as possible, but also affords the advantage of preventing the inadvertent telegraphing of FPL's commercial intentions to the market, thus helping to ensure favorable pricing for FPL's

Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)

FPL reporting systems comprehensively identify, measure, and monitor all forms of risk associated with fuel procurement activities.

FPL's philosophy on reporting is that it should be timely, consistent, flexible, and transparent. Timely and consistent reporting of risk information is critical to the effective management of risk. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, current and historical pricing database, deal information, valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

Specifically, several reports are available at FPL to monitor risk:

Daily Management Report

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details the current Mark to Market (spot and forward), unrealized Mark to Market changes, and VaR. This report is published only after proper and thorough discussion between Risk Management and desk heads, if necessary for clarification, and resolution of any issues raised.

Credit Exposure Reporting

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details:

- Allowable deal types by counterparty
- Restrictions on counterparties

EMC Update

The Vice President Trading Risk Management provides a formal update to the EMC on a monthly basis. The agenda for the update will be agreed in advance with the EMC Chairman, but at a minimum contains the following items:

- Summary and explanation of significant changes in market risk and fair value;
- Summary and explanation of significant changes in credit risk;
- Exceptions to Risk Management Policy; and
- Minutes of previous EMC update for approval.

APPENDIX I

FUEL COST RECOVERY

EXHIBIT GJY-3

DOCKET NO. 20210001-EI

PAGES 1-4

SEPTEMBER 3, 2021

APPENDIX I
FUEL COST RECOVERY

TABLE OF CONTENTS

<u>PAGE</u>	<u>DESCRIPTION</u>	<u>SPONSOR</u>
3	Projected Dispatch Costs	G. Yupp
3	Projected Availability of Natural Gas	G. Yupp
4	Projected Unit Availabilities and Outage Schedules	G. Yupp

Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January 2022 Through December 2022

<u>Light Oil</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>
Ultra-Low Sulfur Distillate (\$/Bbl)	95.01	94.70	94.16	93.41	92.90	92.57	92.49	92.43	92.39	92.38	92.36	92.31
Ultra-Low Sulfur Distillate (\$/MMBtu)	16.30	16.24	16.15	16.02	15.93	15.88	15.86	15.85	15.85	15.85	15.84	15.83
<u>Coal</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>
Scherer (\$/MMBtu)	2.59	2.60	2.59	2.58	2.57	2.58	2.60	2.61	2.61	2.60	2.61	2.62
Daniel (\$/MMBtu)	2.66	2.64	2.64	2.65	2.64	2.64	2.93	2.93	2.93	2.92	2.92	2.93
<u>Natural Gas Dispatch Price</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>
Firm FGT (\$/MMBtu)	4.28	4.20	3.96	3.40	3.33	3.36	3.40	3.41	3.40	3.40	3.44	3.57
Firm Gulfstream (\$/MMBtu)	4.20	4.12	3.87	3.23	3.19	3.22	3.28	3.29	3.27	3.25	3.37	3.51
Firm Sabal Trail/FSC (\$/MMBtu)	4.26	4.19	3.94	3.37	3.31	3.34	3.38	3.39	3.37	3.38	3.46	3.58
Firm Gulf South (\$/MMBtu)	4.03	3.97	3.71	3.14	3.03	3.07	3.14	3.15	3.14	3.11	3.21	3.38
Non-Firm FGT (\$/MMBtu)	5.30	5.21	4.97	4.43	4.37	4.40	4.43	4.44	4.43	4.43	4.45	4.57
Non-Firm Gulfstream (\$/MMBtu)	5.13	5.03	4.80	4.26	4.20	4.23	4.27	4.28	4.26	4.27	4.29	4.40
<u>Natural Gas Transportation</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>
Delivery Transportation												
Firm FGT (MMBtu/Day)	1,237,000	1,237,000	1,237,000	1,326,000	1,361,000	1,361,000	1,361,000	1,361,000	1,361,000	1,326,000	1,237,000	1,237,000
Firm Gulfstream (MMBtu/Day)	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000
Firm Sabal Trail/FSC (MMBtu/Day)	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Firm Gulf South (MMBtu/Day)	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Non-Firm FGT (MMBtu/Day)	100,000	100,000	100,000	100,000	75,000	50,000	50,000	50,000	50,000	75,000	100,000	100,000
Non-Firm Gulfstream (MMBtu/Day)	50,000	50,000	50,000	50,000	50,000	50,000	-	-	-	-	50,000	50,000
Total Projected Delivery Availability (MMBtu/Day)	2,712,000	2,712,000	2,712,000	2,801,000	2,811,000	2,786,000	2,736,000	2,736,000	2,736,000	2,726,000	2,712,000	2,712,000
Upstream Transportation												
Firm SESH (MMBtu/Day)	80,000	80,000	80,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Firm Transco (MMBtu/Day)	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500
Firm Gulf South (MMBtu/Day)	329,000	329,000	329,000	444,000	345,000	345,000	345,000	345,000	345,000	345,000	200,000	200,000
Total Upstream Availability (MMBtu/Day)	530,500	530,500	530,500	745,500	646,500	646,500	646,500	646,500	646,500	646,500	501,500	501,500

**CONSOLIDATED FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY 2022 THROUGH DECEMBER 2022**

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral 3	1.1	5.5	11.0	02/15/22 - 03/22/22	03/17/22 - 03/27/22	03/23/22 - 04/24/22	04/24/22 - 05/26/22	
Dania Beach	0.0	5.5	0.0	NONE				
Daniel 1	0.9	5.5	13.4	9/28/22 - 11/15/22				
Daniel 2	0.9	5.5	0.0	NONE				
Ft. Myers 2	0.7	5.5	1.6	11/17/22 - 11/24/22	11/30/22 - 12/07/22	12/08/22 - 12/15/22		
Ft. Myers 3A	0.8	5.5	1.9	01/18/22 - 01/25/22				
Ft. Myers 3B	0.8	5.5	1.9	01/25/22 - 02/01/22				
Ft. Myers 3C	0.8	5.5	1.9	02/01/22 - 02/08/22				
Ft. Myers 3D	0.8	5.5	1.9	02/08/22 - 02/15/22				
GCEC 4	0.9	5.5	0.0	NONE				
GCEC 5	0.9	5.5	0.0	NONE				
GCEC 6	0.9	5.5	0.0	NONE				
GCEC 7	0.9	5.5	21.4	3/15/22 - 5/31/22				
Lauderdale 6A	0.5	5.5	1.9	01/10/22 - 01/17/22				
Lauderdale 6B	0.5	5.5	1.9	01/17/22 - 01/24/22				
Lauderdale 6C	0.5	5.5	1.9	01/24/22 - 01/31/22				
Lauderdale 6D	0.5	5.5	1.9	01/31/22 - 02/07/22				
Lauderdale 6E	0.5	5.5	1.9	02/07/22 - 02/14/22				
Manatee 3	0.6	5.5	12.1	04/07/22 - 05/05/22	10/01/22 - 10/24/22	10/12/22 - 11/04/22	04/01/22 - 04/24/22	04/24/22 - 05/17/22
Martin 3	0.6	5.5	19.2	10/05/22 - 12/14/22				
Martin 4	0.6	5.5	2.7	04/26/22 - 05/06/22				
Martin 8	1.0	5.5	6.2	03/28/22 - 04/07/22	06/01/22 - 06/24/22	11/15/22 - 12/12/22		
Okeechobee 1	1.5	5.5	8.0	03/05/22 - 03/19/22	10/01/22 - 11/16/22	NONE		
Port Everglades 5	1.5	5.5	9.6	10/10/22 - 11/14/22				
Riviera 5	1.1	5.5	2.7	03/01/22 - 03/11/22				
Sanford 4	0.4	5.5	3.5	02/26/22 - 03/05/22	11/28/22 - 12/21/22			
Sanford 5	0.4	5.5	2.7	02/16/22 - 02/26/22				
Scherer 3	0.8	5.5	12.1	3/12/22 - 4/24/22				
Smith 3	0.6	5.5	0.0	NONE				
St. Lucie 1	1.3	1.3	8.2	09/03/22 - 10/03/22				
St. Lucie 2	1.3	1.3	0.0	NONE				
Turkey Point 3	1.3	1.3	0.0	NONE				
Turkey Point 4	1.3	1.3	7.9	03/12/22 - 04/10/22				
Turkey Point 5	0.6	5.5	1.9	12/08/22 - 12/15/22				
West County 1	0.8	5.5	9.1	09/15/22 - 11/04/22	11/04/22 - 12/24/22			
West County 2	0.8	5.5	26.0	02/15/22 - 04/26/22	04/01/22 - 05/21/22	05/21/22 - 07/10/22		
West County 3	0.8	5.5	2.7	11/27/22 - 12/07/22				

GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY THROUGH DECEMBER, 2020

CRR-1
DOCKET NO. 20210001-EI
FPL Witness: Charles R. Rote
Exhibit No.: _____
Pages 1 - 20
March 16, 2021

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2020

<u>INDEX OF MANUAL PAGES</u>	<u>TITLES</u>
6.203.001	Index of Manual Pages
6.203.002	GPIF Reward/(Penalty) Table (Actual)
6.203.003	GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)
6.203.004	Derivation of System Actual GPIF Points
6.203.005	Actual Equivalent Availability and Adjustments Summary
6.203.006	EAF Adjustment Documentation
6.203.007	Adjustments to Average Net Operating Heat Rates and Adjustments Summary
6.203.008 - 6.203.019	GPIF Units Points Tables
6.203.020	Planned Outages Schedule (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2020

GENERATING PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) (\$000)		GENERATING PERFORMANCE INCENTIVE FACTOR (\$000)	
-----		-----		-----	
+ 10		37,800		18,900	
+ 9		34,020		17,010	
+ 8		30,240		15,120	
+ 7		26,460		13,230	
+ 6		22,680		11,340	
+ 5		18,900		9,450	
+ 4		15,120		7,560	
+ 3	<----- 3.3814	11,340	<----- 12,780.585	5,670	<----- 6,390.846
+ 2		7,560		3,780	
+ 1		3,780		1,890	
0		0		0	
- 1		(3,780)		(1,890)	
- 2		(7,560)		(3,780)	
- 3		(11,340)		(5,670)	
- 4		(15,120)		(7,560)	
- 5		(18,900)		(9,450)	
- 6		(22,680)		(11,340)	
- 7		(26,460)		(13,230)	
- 8		(30,240)		(15,120)	
- 9		(34,020)		(17,010)	
- 10		(37,800)		(18,900)	

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2020

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY	\$ 20,848,759,623
	END OF MONTH BALANCE OF COMMON EQUITY	
LINE 2	MONTH OF January 2020	\$ 22,330,385,403
LINE 3	MONTH OF February 2020	\$ 22,516,248,636
LINE 4	MONTH OF March 2020	\$ 22,728,068,904
LINE 5	MONTH OF April 2020	\$ 23,437,956,730
LINE 6	MONTH OF May 2020	\$ 23,888,855,423
LINE 7	MONTH OF June 2020	\$ 24,175,703,048
LINE 8	MONTH OF July 2020	\$ 24,965,854,968
LINE 9	MONTH OF August 2020	\$ 25,245,182,083
LINE 10	MONTH OF September 2020	\$ 23,679,561,601
LINE 11	MONTH OF October 2020	\$ 23,870,379,874
LINE 12	MONTH OF November 2020	\$ 24,073,471,268
LINE 13	MONTH OF December 2020	\$ 23,746,365,744
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)	\$ 23,500,522,562
LINE 15	25 BASIS POINTS	0.0025
LINE 16	REVENUE EXPANSION FACTOR	75.4238%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)	\$ 77,894,917
LINE 18	JURISDICTIONAL SALES	113,530,952,000 KWH
LINE 19	TOTAL SALES	121,741,451,721 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)	93.26%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)	\$ 72,644,800
LINE 22	INCENTIVE CAP (50 PERCENT OF PROJECTED FUEL SAVINGS AT 10 GPIF-POINT LEVEL FROM SHEET NO. 3.515)	\$ 18,900,000
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)	\$ 18,900,000

Note: Line 22 and 23 are as approved by Commission order PSC-13-0665-FOF-EI dated 12/18/13 effective 1/1/14.

JANUARY THROUGH DECEMBER, 2020

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Cape Canaveral 3	EAF	1.24	10.00	.1240
Cape Canaveral 3	ANOHR	6.29	0.00	.0000
Manatee 3	EAF	0.42	-6.00	-.0252
Manatee 3	ANOHR	3.34	0.00	.0000
Ft. Myers 2	EAF	0.61	-4.40	-.0268
Ft. Myers 2	ANOHR	6.02	10.00	.6020
Port Everglades 5	EAF	2.17	10.00	.2170
Port Everglades 5	ANOHR	10.18	0.00	.0000
Riviera 5	EAF	1.18	-6.00	-.0708
Riviera 5	ANOHR	6.32	0.00	.0000
St. Lucie 1	EAF	9.86	10.00	.9860
St. Lucie 1	ANOHR	1.09	0.00	.0000
St. Lucie 2	EAF	6.81	10.00	.6810
St. Lucie 2	ANOHR	0.74	0.00	.0000
Turkey Point 3	EAF	6.36	-1.67	-.1062
Turkey Point 3	ANOHR	1.76	10.00	.1760
Turkey Point 4	EAF	5.95	2.33	.1386
Turkey Point 4	ANOHR	1.48	0.00	.0000
West County 1	EAF	1.31	10.00	.1310
West County 1	ANOHR	6.70	0.00	.0000
West County 2	EAF	1.62	-6.00	-.0972
West County 2	ANOHR	8.28	9.30	.7700
West County 3	EAF	1.61	-7.33	-.1180
West County 3	ANOHR	8.66	0.00	.0000

GPIF System Total:

100.00-----
3.3814

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS
JANUARY THROUGH DECEMBER, 2020

1	2	3	4	5	6	7	8	9			ACTUAL FUEL SAVINGS/ (LOSS) (\$000)
UNIT	ACTUAL				PLANNED OUTAGE ADJ TO EAF ⁽¹⁾	ADJUSTED ACTUAL EAF	TARGET EAF	POINTS FROM TABLES	ORIGINAL PLANNED OUTAGE DATES	ACTUAL OUTAGE DATES	
	FOF	MOF	POF	EAF							
Cape Canaveral 3	0.2	2.9	12.0	84.9	2.7	87.6	83.4	10.00	02/12/20 - 03/26/20; 02/29/20 - 03/27/20	4/4/20-5/12/20; 10/20/20-11/23/2020 10/20/20-11/19/20	469.0
Manatee 3	0.2	7.4	0.0	92.5	-2.7	89.8	91.3	-6.00	11/12/20 - 11/18/20; 11/19/20 - 11/25/20	NONE	(94.8)
Ft. Myers 2	0.6	6.1	2.2	91.2	-2.2	89.0	90.1	-4.40	02/15/20 - 02/21/20; 02/22/20 - 02/28/20 09/01/20 - 09/14/20; 09/15/20 - 09/28/20 11/01/20 - 11/14/20	9/4/-20-9/14/20; 12/4/20-12/15/20 3/20/20-4/4/20; 11/28/20-12/10/20	(102.1)
Port Everglades 5	0.5	4.1	15.1	80.2	7.5	87.7	81.8	10.00	04/05/20 - 05/02/20; 05/05/20 - 06/14/20 05/17/20 - 05/28/20	1/17/20-3/7/20; 5/19/20-6/1/20 10/16/20-11/30/20; 9/13/20-10/14/20	822.0
Riviera 5	2.5	7.3	0.0	90.1	-6.9	83.2	84.7	-6.00	10/15/20 - 11/11/20;	NONE	(267.6)
St. Lucie 1	0.1	0.0	0.1	99.8	0.1	99.9	87.4	10.00	NONE	7/29/20	3,728.0
St. Lucie 2	0.7	0.0	8.2	91.1	0.3	91.4	85.7	10.00	02/17/20 - 03/17/20	2/15/20-3/20/20; 12/14/20-12/15/20	2,576.0
Turkey Point 3	6.9	0.0	7.8	85.4	-0.1	85.2	85.7	-1.67	03/30/20 - 04/28/20	3/28/20-4/29/20	(401.3)
Turkey Point 4	5.6	0.0	11.8	82.6	0.8	83.4	82.7	2.33	10/05/20 - 11/14/20	10/1/20-11/12/20; 11/17/20-11/24/20	524.3
West County 1	0.4	2.3	23.3	74.0	-0.8	73.2	68.5	10.00	03/20/20 - 04/08/20; 05/01/20 - 05/20/20 10/07/20 - 12/20/20	3/6/20/3/26/20; 10/14/20-12/31/20 10/14/20-12/31/20	496.0
West County 2	0.8	7.9	0.0	91.4	-2.7	88.7	90.2	-6.00	04/09/20 - 04/18/20; 04/11/20 - 04/15/20 04/11/20 - 04/20/20; 04/13/20 - 04/22/20	NONE	(368.4)
West County 3	1.1	9.6	3.6	85.7	-2.6	83.1	85.3	-7.33	09/06/20 - 09/29/20; 09/09/20 - 10/02/20 09/12/20 - 09/29/20; 09/12/20 - 10/05/20	8/26/20-10/15/20	(445.7)
											6,935.405

(1) EQUIVALENT AVAILABILITY ADJUSTMENT DUE TO PLANNED OUTAGE ACTUAL DURATION VERSUS TARGET DURATION
SEE 6.203.006 FOR FORMULAS AND CALCULATION DATA

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2020

1	2	3	4	5	6	7	8	9			
		ACTUAL		TARGET ⁽²⁾	ADJUST. ⁽³⁾		ADJUST. ⁽⁵⁾	GPIF ⁽⁶⁾	ACTUAL		
	HEAT RATE ⁽¹⁾	NOF	ANOHR	ANOHR AT	TO	TARGET ⁽⁴⁾	ACTUAL	POINTS	FUEL		
UNIT	FORMULA	%	BTU/KWH	ACTUAL NOF	ANOHR	ANOHR	ANOHR	FROM	SAV./ (LOSS)		
				BTU/KWH	BTU/KWH	BTU/KWH	BTU/KWH	TABLE	\$000		
Cape Canaveral 3	ANOHR=	-1.21 x NOF +	6,705	62.3	6,655	6,630	25	6,615	6,640	0.00	0.0
Manatee 3	ANOHR=	-2.32 x NOF +	7,039	70.8	6,901	6,875	26	6,880	6,906	0.00	0.0
Ft. Myers 2	ANOHR=	-7.88 x NOF +	7,768	63.5	7,106	7,268	-162	7,342	7,180	10.00	2277.0
Port Everglades 5	ANOHR=	-10.43 x NOF +	7,434	60.2	6,750	6,806	-56	6,525	6,469	0.00	0.0
Riviera 5	ANOHR=	-4.44 x NOF +	6,909	60.2	6,602	6,642	-40	6,567	6,527	0.00	0.0
St. Lucie 1	ANOHR=	-35.11 x NOF +	13,876	101.3	10,342	10,319	23	10,421	10,444	0.00	0.0
St. Lucie 2	ANOHR=	-20.11 x NOF +	12,239	101.9	10,200	10,190	10	10,262	10,272	0.00	0.0
Turkey Point 3	ANOHR=	-118.45 x NOF +	22,907	98.1	10,499	11,287	-788	11,228	10,440	10.00	661.0
Turkey Point 4	ANOHR=	-28.86 x NOF +	13,728	100.5	10,764	10,828	-64	10,865	10,801	0.00	0.0
West County 1	ANOHR=	-6.34 x NOF +	7,575	69.7	7,089	7,133	-44	7,060	7,016	0.00	0.0
West County 2	ANOHR=	-6.85 x NOF +	7,502	69.2	6,887	7,028	-141	6,918	6,777	9.30	2907.2
West County 3	ANOHR=	-6.31 x NOF +	7,442	67.5	6,999	7,016	-17	6,921	6,904	0.00	0.0

1) THESE FORMULAS ARE AS APPROVED BY THE COMMISSION IN THE PROJECTION FILING AND
ARE BASED ON MONTHLY ACTUAL DATA

5,845.180

2) CALCULATED FROM ANOHR FORMULA IN COLUMN 2 USING ACTUAL NOF IN COLUMN 3

3) ADJUSTMENT TO ANOHR=ACTUAL ANOHR - TARGET ANOHR AT ACTUAL NOF (COLUMN 6 = COLUMN 4 - COLUMN 5).

4) AT TARGET NOF AS APPROVED BY THE COMMISSION IN PROJECTED DATA.

5) AT TARGET NOF, ADJUSTED ACTUAL ANOHR = TARGET ANOHR + ADJUSTMENTS (COLUMN 8 = COLUMN 7 + COLUMN 6).

6) OBTAINED FROM THE GPIF POINT TABLES USING THE COMMISSION APPROVED TARGETS.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: Cape Canaveral 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	469.0 <- Fuel Sav/(Loss) 469.0	85.9 <- Adj. Act. EAF= 87.6	+10	2,376.0	6,493
+9	422.1	85.7	+9	2,138.4	6,498
+8	375.2	85.4	+8	1,900.8	6,502
+7	328.3	85.2	+7	1,663.2	6,507
+6	281.4	84.9	+6	1,425.6	6,512
+5	234.5	84.7	+5	1,188.0	6,517
+4	187.6	84.4	+4	950.4	6,521
+3	140.7	84.2	+3	712.8	6,526
+2	93.8	83.9	+2	475.2	6,531
+1	46.9	83.7	+1	237.6	6,535
				0	6,540
0	0	83.4	0	0 <- Fuel Sav/(Loss)	6,615 <- Adj. Act. HR=6,640
				0	6,690
-1	(46.9)	83.2	-1	(237.6)	6,695
-2	(93.8)	82.9	-2	(475.2)	6,699
-3	(140.7)	82.7	-3	(712.8)	6,704
-4	(187.6)	82.4	-4	(950.4)	6,709
-5	(234.5)	82.2	-5	(1,188.0)	6,714
-6	(281.4)	81.9	-6	(1,425.6)	6,718
-7	(328.3)	81.7	-7	(1,663.2)	6,723
-8	(375.2)	81.4	-8	(1,900.8)	6,728
-9	(422.1)	81.2	-9	(2,138.4)	6,732
-10	(469.0)	80.9	-10	(2,376.0)	6,737
----- WEIGHTING FACTOR =		1.24	----- WEIGHTING FACTOR =		6.29

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: Manatee 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	158.0	93.8	+10	1,264.0	6,758
+9	142.2	93.6	+9	1,137.6	6,763
+8	126.4	93.3	+8	1,011.2	6,767
+7	110.6	93.1	+7	884.8	6,772
+6	94.8	92.8	+6	758.4	6,777
+5	79.0	92.6	+5	632.0	6,782
+4	63.2	92.3	+4	505.6	6,786
+3	47.4	92.1	+3	379.2	6,791
+2	31.6	91.8	+2	252.8	6,796
+1	15.8	91.6	+1	126.4	6,800
				0	6,805
0	0	91.3	0	0 <- Fuel Sav/(Loss)	6,880 <- Adj. Act. HR=6.906
				0	6,955
-1	(15.8)	91.1	-1	(126.4)	6,960
-2	(31.6)	90.8	-2	(252.8)	6,964
-3	(47.4)	90.6	-3	(379.2)	6,969
-4	(63.2)	90.3	-4	(505.6)	6,974
-5	(79.0)	90.1	-5	(632.0)	6,979
-6	(94.8) <- Fuel Sav/(Loss) (94.8)	89.8 <- Adj. Act. EAF= 89.8	-6	(758.4)	6,983
-7	(110.6)	89.6	-7	(884.8)	6,988
-8	(126.4)	89.3	-8	(1,011.2)	6,993
-9	(142.2)	89.1	-9	(1,137.6)	6,997
-10	(158.0)	88.8	-10	(1,264.0)	7,002
----- WEIGHTING FACTOR =		0.42	----- WEIGHTING FACTOR =		3.34

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: Ft. Myers 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	232.0	92.6	+10	2,277.0 <- Fuel Sav/(Loss) 2,277.0	7,229 <- Adj. Act. HR=7,180
+9	208.8	92.4	+9	2,049.3	7,233
+8	185.6	92.1	+8	1,821.6	7,237
+7	162.4	91.9	+7	1,593.9	7,240
+6	139.2	91.6	+6	1,366.2	7,244
+5	116.0	91.4	+5	1,138.5	7,248
+4	92.8	91.1	+4	910.8	7,252
+3	69.6	90.9	+3	683.1	7,256
+2	46.4	90.6	+2	455.4	7,259
+1	23.2	90.4	+1	227.7	7,263
				0	7,267
0	0	90.1	0	0	7,342
				0	7,417
-1	(23.2)	89.9	-1	(227.7)	7,421
-2	(46.4)	89.6	-2	(455.4)	7,425
-3	(69.6)	89.4	-3	(683.1)	7,428
-4	(92.8)	89.1	-4	(910.8)	7,432
-5	(116.0) <- Fuel Sav/(Loss) (102.1)	88.9 <- Adj. Act. EAF= 89.0	-5	(1,138.5)	7,436
-6	(139.2)	88.6	-6	(1,366.2)	7,440
-7	(162.4)	88.4	-7	(1,593.9)	7,444
-8	(185.6)	88.1	-8	(1,821.6)	7,447
-9	(208.8)	87.9	-9	(2,049.3)	7,451
-10	(232.0)	87.6	-10	(2,277.0)	7,455
----- WEIGHTING FACTOR =		0.61	----- WEIGHTING FACTOR =		6.02

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: Port Everglades 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	822.0 <- Fuel Sav/(Loss) 822.0	84.8 <- Adj. Act. EAF= 87.7	+10	3,847.0	6,355
+9	739.8	84.5	+9	3,462.3	6,365
+8	657.6	84.2	+8	3,077.6	6,374
+7	575.4	83.9	+7	2,692.9	6,384
+6	493.2	83.6	+6	2,308.2	6,393
+5	411.0	83.3	+5	1,923.5	6,403
+4	328.8	83.0	+4	1,538.8	6,412
+3	246.6	82.7	+3	1,154.1	6,422
+2	164.4	82.4	+2	769.4	6,431
+1	82.2	82.1	+1	384.7	6,441
				0 <- Fuel Sav/(Loss)	6,450 <- Adj. Act. HR=6,469
0	0	81.8	0	0	6,525
				0	6,600
-1	(82.2)	81.5	-1	(384.7)	6,610
-2	(164.4)	81.2	-2	(769.4)	6,619
-3	(246.6)	80.9	-3	(1,154.1)	6,629
-4	(328.8)	80.6	-4	(1,538.8)	6,638
-5	(411.0)	80.3	-5	(1,923.5)	6,648
-6	(493.2)	80.0	-6	(2,308.2)	6,657
-7	(575.4)	79.7	-7	(2,692.9)	6,667
-8	(657.6)	79.4	-8	(3,077.6)	6,676
-9	(739.8)	79.1	-9	(3,462.3)	6,686
-10	(822.0)	78.8	-10	(3,847.0)	6,695
----- WEIGHTING FACTOR =		2.17	----- WEIGHTING FACTOR =		10.18

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: Riviera 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	446.0	87.2	+10	2,389.0	6,450
+9	401.4	87.0	+9	2,150.1	6,454
+8	356.8	86.7	+8	1,911.2	6,458
+7	312.2	86.5	+7	1,672.3	6,463
+6	267.6	86.2	+6	1,433.4	6,467
+5	223.0	86.0	+5	1,194.5	6,471
+4	178.4	85.7	+4	955.6	6,475
+3	133.8	85.5	+3	716.7	6,479
+2	89.2	85.2	+2	477.8	6,484
+1	44.6	85.0	+1	238.9	6,488
				0 <- Fuel Sav/(Loss)	6,492 <- Adj. Act. HR=6,527
0	0	84.7	0	0	6,567
				0	6,642
-1	(44.6)	84.5	-1	(238.9)	6,646
-2	(89.2)	84.2	-2	(477.8)	6,650
-3	(133.8)	84.0	-3	(716.7)	6,655
-4	(178.4)	83.7	-4	(955.6)	6,659
-5	(223.0)	83.5	-5	(1,194.5)	6,663
-6	(267.6) <- Fuel Sav/(Loss) (267.6)	83.2 <- Adj. Act. EAF= 83.2	-6	(1,433.4)	6,667
-7	(312.2)	83.0	-7	(1,672.3)	6,671
-8	(356.8)	82.7	-8	(1,911.2)	6,676
-9	(401.4)	82.5	-9	(2,150.1)	6,680
-10	(446.0)	82.2	-10	(2,389.0)	6,684
----- WEIGHTING FACTOR =		1.18	----- WEIGHTING FACTOR =		6.32

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: St. Lucie 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	3,728.0 <- Fuel Sav/(Loss) 3,728.0	90.9 <- Adj. Act. EAF= 99.9	+10	413.0	10,317
+9	3,355.2	90.6	+9	371.7	10,320
+8	2,982.4	90.2	+8	330.4	10,323
+7	2,609.6	89.9	+7	289.1	10,326
+6	2,236.8	89.5	+6	247.8	10,329
+5	1,864.0	89.2	+5	206.5	10,332
+4	1,491.2	88.8	+4	165.2	10,334
+3	1,118.4	88.5	+3	123.9	10,337
+2	745.6	88.1	+2	82.6	10,340
+1	372.8	87.8	+1	41.3	10,343
				0	10,346
0	0	87.4	0	0 <- Fuel Sav/(Loss)	10,421 <- Adj. Act. HR=10.444
				0	10,496
-1	(372.8)	87.1	-1	(41.3)	10,499
-2	(745.6)	86.7	-2	(82.6)	10,502
-3	(1,118.4)	86.4	-3	(123.9)	10,505
-4	(1,491.2)	86.0	-4	(165.2)	10,508
-5	(1,864.0)	85.7	-5	(206.5)	10,511
-6	(2,236.8)	85.3	-6	(247.8)	10,513
-7	(2,609.6)	85.0	-7	(289.1)	10,516
-8	(2,982.4)	84.6	-8	(330.4)	10,519
-9	(3,355.2)	84.3	-9	(371.7)	10,522
-10	(3,728.0)	83.9	-10	(413.0)	10,525
-----			-----		
WEIGHTING FACTOR =		9.86	WEIGHTING FACTOR =		1.09

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: St. Lucie 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	2,576.0 <- Fuel Sav/(Loss) 2,576.0	88.7 <- Adj. Act. EAF= 91.4	+10	278.0	10,169
+9	2,318.4	88.4	+9	250.2	10,171
+8	2,060.8	88.1	+8	222.4	10,173
+7	1,803.2	87.8	+7	194.6	10,174
+6	1,545.6	87.5	+6	166.8	10,176
+5	1,288.0	87.2	+5	139.0	10,178
+4	1,030.4	86.9	+4	111.2	10,180
+3	772.8	86.6	+3	83.4	10,182
+2	515.2	86.3	+2	55.6	10,183
+1	257.6	86.0	+1	27.8	10,185
				0	10,187
0	0	85.7	0	0 <- Fuel Sav/(Loss)	10,262 <- Adj. Act. HR=10,272
				0	10,337
-1	(257.6)	85.4	-1	(27.8)	10,339
-2	(515.2)	85.1	-2	(55.6)	10,341
-3	(772.8)	84.8	-3	(83.4)	10,342
-4	(1,030.4)	84.5	-4	(111.2)	10,344
-5	(1,288.0)	84.2	-5	(139.0)	10,346
-6	(1,545.6)	83.9	-6	(166.8)	10,348
-7	(1,803.2)	83.6	-7	(194.6)	10,350
-8	(2,060.8)	83.3	-8	(222.4)	10,351
-9	(2,318.4)	83.0	-9	(250.2)	10,353
-10	(2,576.0)	82.7	-10	(278.0)	10,355
----- WEIGHTING FACTOR =		6.81	----- WEIGHTING FACTOR =		0.74

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: Turkey Point 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	2,403.0	88.7	+10	661.0 <- Fuel Sav/(Loss) 661.0	11,038 <- Adj. Act. HR=10,440
+9	2,162.7	88.4	+9	594.9	11,050
+8	1,922.4	88.1	+8	528.8	11,061
+7	1,682.1	87.8	+7	462.7	11,073
+6	1,441.8	87.5	+6	396.6	11,084
+5	1,201.5	87.2	+5	330.5	11,096
+4	961.2	86.9	+4	264.4	11,107
+3	720.9	86.6	+3	198.3	11,119
+2	480.6	86.3	+2	132.2	11,130
+1	240.3	86.0	+1	66.1	11,142
				0	11,153
0	0	85.7	0	0	11,228
				0	11,303
-1	(240.3)	85.4	-1	(66.1)	11,315
-2	(480.6) <- Fuel Sav/(Loss) (401.3)	85.1 <- Adj. Act. EAF= 85.2	-2	(132.2)	11,326
-3	(720.9)	84.8	-3	(198.3)	11,338
-4	(961.2)	84.5	-4	(264.4)	11,349
-5	(1,201.5)	84.2	-5	(330.5)	11,361
-6	(1,441.8)	83.9	-6	(396.6)	11,372
-7	(1,682.1)	83.6	-7	(462.7)	11,384
-8	(1,922.4)	83.3	-8	(528.8)	11,395
-9	(2,162.7)	83.0	-9	(594.9)	11,407
-10	(2,403.0)	82.7	-10	(661.0)	11,418
----- WEIGHTING FACTOR =		6.36	----- WEIGHTING FACTOR =		1.76

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: Turkey Point 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	2,250.0	85.7	+10	561.0	10,620
+9	2,025.0	85.4	+9	504.9	10,637
+8	1,800.0	85.1	+8	448.8	10,654
+7	1,575.0	84.8	+7	392.7	10,671
+6	1,350.0	84.5	+6	336.6	10,688
+5	1,125.0	84.2	+5	280.5	10,705
+4	900.0	83.9	+4	224.4	10,722
+3	675.0	83.6	+3	168.3	10,739
+2	450.0	83.3	+2	112.2	10,756
+1	225.0	83.0	+1	56.1	10,773
				0	10,790
				<- Fuel Sav/(Loss)	<- Adj. Act. HR=10,801
0	0	82.7	0	0	10,865
				0	10,940
-1	(225.0)	82.4	-1	(56.1)	10,957
-2	(450.0)	82.1	-2	(112.2)	10,974
-3	(675.0)	81.8	-3	(168.3)	10,991
-4	(900.0)	81.5	-4	(224.4)	11,008
-5	(1,125.0)	81.2	-5	(280.5)	11,025
-6	(1,350.0)	80.9	-6	(336.6)	11,042
-7	(1,575.0)	80.6	-7	(392.7)	11,059
-8	(1,800.0)	80.3	-8	(448.8)	11,076
-9	(2,025.0)	80.0	-9	(504.9)	11,093
-10	(2,250.0)	79.7	-10	(561.0)	11,110
WEIGHTING FACTOR =		5.95	WEIGHTING FACTOR =		1.48

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: West County 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	496.0 <- Fuel Sav/(Loss) 496.0	71.0 <- Adj. Act. EAF= 73.2	+10	2,532.0	6,902
+9	446.4	70.8	+9	2,278.8	6,910
+8	396.8	70.5	+8	2,025.6	6,919
+7	347.2	70.3	+7	1,772.4	6,927
+6	297.6	70.0	+6	1,519.2	6,935
+5	248.0	69.8	+5	1,266.0	6,944
+4	198.4	69.5	+4	1,012.8	6,952
+3	148.8	69.3	+3	759.6	6,960
+2	99.2	69.0	+2	506.4	6,968
+1	49.6	68.8	+1	253.2	6,977
				0 <- Fuel Sav/(Loss)	6,985 <- Adj. Act. HR=7,016
0	0	68.5	0	0	7,060
				0	7,135
-1	(49.6)	68.3	-1	(253.2)	7,143
-2	(99.2)	68.0	-2	(506.4)	7,152
-3	(148.8)	67.8	-3	(759.6)	7,160
-4	(198.4)	67.5	-4	(1,012.8)	7,168
-5	(248.0)	67.3	-5	(1,266.0)	7,177
-6	(297.6)	67.0	-6	(1,519.2)	7,185
-7	(347.2)	66.8	-7	(1,772.4)	7,193
-8	(396.8)	66.5	-8	(2,025.6)	7,201
-9	(446.4)	66.3	-9	(2,278.8)	7,210
-10	(496.0)	66.0	-10	(2,532.0)	7,218
-----				-----	
WEIGHTING FACTOR =		1.31		WEIGHTING FACTOR =	
				6.70	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: West County 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	614.0	92.7	+10	3,126.0	6,772
+9	552.6	92.5	+9	2,813.4	6,779
+8	491.2	92.2	+8	2,500.8	6,786
+7	429.8	92.0	+7	2,188.2	6,793
+6	368.4	91.7	+6	1,875.6	6,800
+5	307.0	91.5	+5	1,563.0	6,808
+4	245.6	91.2	+4	1,250.4	6,815
+3	184.2	91.0	+3	937.8	6,822
+2	122.8	90.7	+2	625.2	6,829
+1	61.4	90.5	+1	312.6	6,836
				0	6,843
0	0	90.2	0	0	6,918
				0	6,993
-1	(61.4)	90.0	-1	(312.6)	7,000
-2	(122.8)	89.7	-2	(625.2)	7,007
-3	(184.2)	89.5	-3	(937.8)	7,014
-4	(245.6)	89.2	-4	(1,250.4)	7,021
-5	(307.0)	89.0	-5	(1,563.0)	7,029
-6	(368.4) <- Fuel Sav/(Loss) (368.4)	88.7 <- Adj. Act. EAF= 88.7	-6	(1,875.6)	7,036
-7	(429.8)	88.5	-7	(2,188.2)	7,043
-8	(491.2)	88.2	-8	(2,500.8)	7,050
-9	(552.6)	88.0	-9	(2,813.4)	7,057
-10	(614.0)	87.7	-10	(3,126.0)	7,064
----- WEIGHTING FACTOR =		1.62	----- WEIGHTING FACTOR =		8.28

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2020

UNIT: West County 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) (\$000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	608.0	88.3	+10	3,274.0	6,758
+9	547.2	88.0	+9	2,946.6	6,767
+8	486.4	87.7	+8	2,619.2	6,776
+7	425.6	87.4	+7	2,291.8	6,784
+6	364.8	87.1	+6	1,964.4	6,793
+5	304.0	86.8	+5	1,637.0	6,802
+4	243.2	86.5	+4	1,309.6	6,811
+3	182.4	86.2	+3	982.2	6,820
+2	121.6	85.9	+2	654.8	6,828
+1	60.8	85.6	+1	327.4	6,837
				0 <- Fuel Sav/(Loss)	6,846 <- Adj. Act. HR=6,904
0	0	85.3	0	0	6,921
				0	6,996
-1	(60.8)	85.0	-1	(327.4)	7,005
-2	(121.6)	84.7	-2	(654.8)	7,014
-3	(182.4)	84.4	-3	(982.2)	7,022
-4	(243.2)	84.1	-4	(1,309.6)	7,031
-5	(304.0)	83.8	-5	(1,637.0)	7,040
-6	(364.8)	83.5	-6	(1,964.4)	7,049
-7	(425.6)	83.2	-7	(2,291.8)	7,058
-8	(486.4) <- Fuel Sav/(Loss) (445.7)	82.9 <- Adj. Act. EAF= 83.1	-8	(2,619.2)	7,066
-9	(547.2)	82.6	-9	(2,946.6)	7,075
-10	(608.0)	82.3	-10	(3,274.0)	7,084
----- WEIGHTING FACTOR =		1.61	----- WEIGHTING FACTOR =		8.66

ACTUAL PLANNED OUTAGES
FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2020

PLANT/UNIT	ACTUAL PLANNED OUTAGE DATE	REASON FOR OUTAGE
Cape Canaveral 3	4/4/20-5/12/20; 10/20/20-11/23/2020 10/20/20-11/19/20	CT-31 CI Major; PCC-30 and CT-31 ST valves, generator minor and DCS minor PCC-30, CT-32 and CT-33 ST valves, generator minor and DCS minor
Manatee 3	NONE	N/A
Ft. Myers 2	9/4/-20-9/14/20; 12/4/20-12/15/20 3/20/20-4/4/20; 11/28/20-12/10/20	CT-2B generator minor; CT-2D generator minor CT-2E generator minor; CT-2F generator minor
Port Everglades 5	1/17/20-3/7/20; 5/19/20-6/1/20 10/16/20-11/30/20; 9/13/20-10/14/20	CT-51 HGP rotor swap and new rotor testing; block planned outage CT-52 planned outage; CT-53 planned outage
Riviera 5	NONE	N/A
St. Lucie 1	7/29/20	Turbine valve test (TVT)
St. Lucie 2	2/15/20-3/20/20 12/14/20-12/15/20	Main Steam Safety Valve (MSSV) testing & Refueling outage Turbine valve test (TVT)
Turkey Point 3	3/28/20-4/29/20	Down power, Refueling and power ascension
Turkey Point 4	10/1/20-11/12/20; 11/17/20-11/24/20	Down power, Refueling and power ascension
West County 1	3/6/20/3/26/20; 10/14/20-12/31/20 10/14/20-12/31/20	CT-1A exhaust duct replacement; annual reliability during 1ST major 1ST major and CT-1B & 1C Annual reliability during 1ST major
West County 2	NONE	N/A
West County 3	8/26/20-10/15/20	CT-3B KAI upgrade, rotor swap and CT exhaust upgrade

EXHIBIT TO THE TESTIMONY OF
CHARLES R. ROTE
IN FPSC DOCKET 20210001-EI

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2020 - DECEMBER 2020 PERIOD

Additions and Corrections to Outages Previously Reported
 for the January 2020 - December 2020 Period

<u>Date</u>	<u>Unit</u>	<u>Change</u>	<u>Outage Type</u>	<u>Hours</u>	<u>MW</u>	<u>Description</u>
January filing	Crist 7	Net Gen				Net Gen trued up
	Daniel 1	PMOH Net Gen		73.4	77.0	Derate entered after filing Net Gen trued up
	Daniel 2	PMOH Net Gen		314.7	173.0	Derate entered after filing Net Gen trued up
	Scherer 3	Net Gen				Net Gen trued up
	Smith 3	MMBTU				Mmbtu trued up
February filing	Scherer 3	Net Gen				Net Gen trued up
	Daniel 1	PMOH Net Gen		71.6	77.0	Derate hours trued up Net Gen trued up
	Daniel 2	Net Gen				Net Gen trued up
	Smith 3	Net Gen				Net Gen trued up
March filing	Crist 7	Net Gen				Net Gen trued up
	Daniel 1	PMOH Net Gen		69.2	77.0	Derate entered after filing Net Gen trued up
	Daniel 2	PMOH Net Gen		714.9	77.0	Derate entered after filing Net Gen trued up
	Scherer 3	Net Gen				Net Gen trued up
April filing	Scherer 3	RSH		720.0		RSH was trued up
May filing	Daniel 1	PMOH		632.0	77.0	Derate entered after filing
	Daniel 2	PMOH		20.1	77.0	Derate entered after filing
June filing	Scherer 3	FOH		24.1	860.0	Start-up failure
	Daniel 1	PMOH		720.0	77.0	Derate entered after filing
	Daniel 2	PMOH		630.9	77.0	Derate entered after filing

Additions and Corrections to Outages Previously Reported
for the January 2020 - December 2020 Period

<u>Date</u>	<u>Unit</u>	<u>Change</u>	<u>Outage Type</u>	<u>Hours</u>	<u>MW</u>	<u>Description</u>
July filing	Scherer 3	LRph		165.0		Reduced LRph on stuck valve. Increased EAF from 99.1 to 99.4
	Daniel 1	PMOH		97.9	77.0	Reduction in hours of derate
	Daniel 2	PMOH		188.5	77.0	Reduction in hours of derate
August filing	Daniel 1	PMOH		142.4	77.0	Reduction in hours of derate
	Daniel 2	LRpm				LRpf changed from 77.1 to 77 EAF changed 90.6% to 90.7%
	GCEC 7	Oper Mbtu				Mmbtu trued up
November filing	Daniel 2	PMOH		241.0	77.0	Increase in hours of derate
December filing	Daniel 1	Net Gen				Net Gen trued up
	Daniel 2	Net Gen				Net Gen trued up
	Scherer 3	Net Gen				Net Gen trued up

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
 for January 2020 - December 2020

<u>Unit</u>	<u>Note</u>	<u>Forecast Planned Outage Schedule</u>	<u>Forecast Hours*</u>	<u>Actual Planned Outage Schedule</u>	<u>Actual Hours*</u>
Smith 3	3	04/28/2020 - 5/6/2020	216.0	2/27/2020 - 3/08/20	233.6
Smith 3	3	9/18/2020 - 10/03/2020	384.0	12/08/2020 - 12/17/2020	197.6
Daniel 1	3	3/24/2020 - 4/01/2020	216.0		
Daniel 1	1	9/26/2020 - 12/11/2020	1848.0	9/26/2020 - 12/09/2020	1781.3
Daniel 2	3	04/10/2020 - 05/17/2020	912.0	03/30/2020 - 05/31/2020	1469.9
GCEC 7	3	03/07/20 - 04/26/20	1224.0	03/20/2020 - 05/30/2020	1689.3

* Planned outage hours in the January 2020 - December 2020 period only.

- Notes:
1. The outage proceeded as scheduled.
 2. The outage was added subsequent to the target filing.
 3. The outage date was changed subsequent to the target filing.
 4. The outage date proceeded as scheduled and extended.

Calculation of Actual Equivalent Availability
for January 2020 - December 2020
Based on Target Planned Outage Hours
Scherer 3

Results of Operations							
	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	24.1	
	0.0	0.0	0.0	0.0	0.0	0.0	24.1
EFOH	0.0	0.0	0.0	0.0	0.0	0.0	
	4.2	0.0	0.0	0.0	0.0	0.0	4.2
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	233.0	0.0	233.0
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	604.5	619.4	650.4	720.0	744.0	548.1	
	0.0	0.0	312.4	744.0	470.2	402.3	5815.3

$$1. \text{ EUOR} = \frac{(\text{FOH} + \text{EFOH} + \text{MOH} + \text{EMOH})}{(\text{PH} - \text{POH} - \text{RSH})} = \frac{(24.1 + 4.2 + 233.0 + 0.0)}{(8784.0 - 0.0 - 5815.3)}$$

$$\text{EUOR} = 0.0880$$

$$2. \text{ EA} = \left[1 - \frac{(\text{POH}^* + \text{EUOR} (\text{PH} - \text{POH}^* - \text{RSH}^*))}{\text{PH}} \right] \times 100$$

$$\text{Target POH}^* = 0.0$$

$$\text{Target RSH}^* = 822.0$$

$$\text{EA} = \left[1 - \frac{(0.0 + 0.0880 (8784.0 - 0.0 - 822.0))}{8784.0} \right] \times 100 = 92.0 \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2020 - December 2020
Based on Target Planned Outage Hours
GCEC 7

Results of Operations							
	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0 0.0	0.0 2.1	0.0 358.0	0.0 744.0	7.4 721.0	0.0 744.0	2576.5
EFOH	0.0 1.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	14.4 0.0	15.4
MOH	0.0 305.0	0.0 351.3	65.6 14.0	0.0 0.0	0.0 0.0	535.1 0.0	1271.1
EMOH	0.0 0.0	0.0 58.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	58.0
PH	744.0 744.0	696.0 744.0	743.0 720.0	720.0 744.0	744.0 721.0	720.0 744.0	8784.0
POH	0.0 0.0	0.0 0.0	264.0 0.0	720.0 0.0	705.2 0.0	0.0 0.0	1689.3
RSH	239.2 1.0	0.0 87.3	8.3 348.0	0.0 0.0	0.0 0.0	0.0 0.0	683.7

$$1. \text{ EUOR} = \frac{(\text{FOH} + \text{EFOH} + \text{MOH} + \text{EMOH})}{(\text{PH} - \text{POH} - \text{RSH})} = \frac{(2576.5 + 15.4 + 1271.1 + 58.0)}{(8784.0 - 1689.3 - 683.7)}$$

$$\text{EUOR} = 0.6116$$

$$2. \text{ EA} = \left[1 - \frac{(\text{POH}^* + \text{EUOR} (\text{PH} - \text{POH}^* - \text{RSH}^*))}{\text{PH}} \right] \times 100$$

$$\text{Target POH}^* = 1223.0$$

$$\text{Target RSH}^* = 2265.0$$

$$\text{EA} = \left[1 - \frac{(1223.0 + 0.6116 (8784.0 - 1223.0 - 2265.0))}{8784.0} \right] \times 100 = 49.2 \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2020 - December 2020
Based on Target Planned Outage Hours
Daniel 1

Results of Operations							
	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	1.3 0.0	0.0 0.0	1.3
EFOH	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0
MOH	0.0 12.2	0.0 0.0	0.0 0.0	84.0 0.0	29.4 0.0	0.0 0.0	125.6
EMOH	11.3 87.9	11.0 69.8	10.6 67.2	0.0 0.0	96.9 0.0	110.4 84.0	549.1
PH	744.0 744.0	696.0 744.0	743.0 720.0	720.0 744.0	744.0 721.0	720.0 744.0	8784.0
POH	0.0 0.0	0.0 0.0	0.0 120.0	0.0 744.0	0.0 721.0	0.0 196.3	1781.3
RSH	670.6 60.5	624.4 0.0	530.4 73.4	636.0 0.0	80.6 0.0	0.0 0.0	2675.8

$$1. \text{ EUOR} = \frac{(\text{FOH} + \text{EFOH} + \text{MOH} + \text{EMOH})}{(\text{PH} - \text{POH} - \text{RSH})} = \frac{(1.3 + 0.0 + 125.6 + 549.1)}{(8784.0 - 1781.3 - 2675.8)}$$

$$\text{EUOR} = 0.1562$$

$$2. \text{ EA} = \left[1 - \frac{(\text{POH}^* + \text{EUOR} (\text{PH} - \text{POH}^* - \text{RSH}^*))}{\text{PH}} \right] \times 100$$

$$\text{Target POH}^* = 2065.0$$

$$\text{Target RSH}^* = 2318.0$$

$$\text{EA} = \left[1 - \frac{(2065.0 + 0.1562 (8784.0 - 2065.0 - 2318.0))}{8784.0} \right] \times 100 = 68.7 \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2020 - December 2020
Based on Target Planned Outage Hours
Daniel 2

Results of Operations							
	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	3.0 0.0	3.0
EFOH	0.0 1.3	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	1.3
MOH	119.6 0.0	6.5 0.0	2.4 3.3	0.0 21.4	0.0 0.0	0.0 0.0	153.2
EMOH	108.5 84.4	79.1 69.5	109.6 96.6	0.0 110.8	3.1 110.6	96.8 97.7	966.7
PH	744.0 744.0	696.0 744.0	743.0 720.0	720.0 744.0	744.0 721.0	720.0 744.0	8784.0
POH	0.0 0.0	0.0 0.0	26.3 0.0	720.0 0.0	723.6 0.0	0.0 0.0	1469.9
RSH	309.2 0.0	326.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 106.5	741.7

$$1. \text{ EUOR} = \frac{(\text{FOH} + \text{EFOH} + \text{MOH} + \text{EMOH})}{(\text{PH} - \text{POH} - \text{RSH})} = \frac{(3.0 + 1.3 + 153.2 + 966.7)}{(8784.0 - 1469.9 - 741.7)}$$

$$\text{EUOR} = 0.1711$$

$$2. \text{ EA} = \left[1 - \frac{(\text{POH}^* + \text{EUOR} (\text{PH} - \text{POH}^* - \text{RSH}^*))}{\text{PH}} \right] \times 100$$

$$\text{Target POH}^* = 888.0$$

$$\text{Target RSH}^* = 2389.0$$

$$\text{EA} = \left[1 - \frac{(888.0 + 0.1711 (8784.0 - 888.0 - 2389.0))}{8784.0} \right] \times 100 = 79.2 \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2020 - December 2020
Based on Target Planned Outage Hours
Smith 3

Results of Operations							
	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	14.3	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	14.3
EFOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	2.5	0.0	0.0	0.0	2.5
MOH	0.0	36.1	198.0	68.2	0.0	7.5	
	0.0	0.0	0.0	0.0	0.0	232.5	542.4
EMOH	0.0	0.0	0.0	2.3	0.0	1.4	
	0.0	0.0	0.0	0.0	0.0	0.0	3.7
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1. \text{ EUOR} = \frac{(\text{FOH} + \text{EFOH} + \text{MOH} + \text{EMOH})}{(\text{PH} - \text{POH} - \text{RSH})} = \frac{(14.3 + 2.5 + 542.4 + 3.7)}{(8784.0 - 0.0 - 0.0)}$$

$$\text{EUOR} = 0.0641$$

$$2. \text{ EA} = \left[1 - \frac{(\text{POH}^* + \text{EUOR} (\text{PH} - \text{POH}^* - \text{RSH}^*))}{\text{PH}} \right] \times 100$$

$$\text{Target POH}^* = 600.0$$

$$\text{Target RSH}^* = 358.0$$

$$\text{EA} = \left[1 - \frac{(600.0 + 0.0641 (8784.0 - 600.0 - 358.0))}{8784.0} \right] \times 100 = 87.5 \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
 for January 2020 - December 2020

(1)	(2)	(3)	(4)	(5)
Unit	Equivalent Availability Target*	Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	Minimum or Maximum Attainable Equivalent Availability*	Availability Points***
Scherer 3	96.8	92.0	95.5	-10.00
GCEC 7	78.4	49.2	75.4	-10.00
Daniel 1	70.9	68.7	70.9	0.00
Daniel 2	84.7	79.2	82.9	-10.00
Smith 3	89.9	87.5	88.3	-10.00

* As appropriate from page 5, Schedule 3 of Exhibit to C. L. Nicholson's September 3, 2019 GPIF Testimony in Docket 20190001-EI.

** Refer to pages 3 through 7 of this Schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
 for January 2020 - December 2020

Scherer 3

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	68352.0 338730.0	37424.0 374542.0	39758.0 179452.0	0.0 0.0	0.0 5492.0	74954.0 124436.0	1243140.0
BTU/Lb*	8331.0 8295.9	8282.9 8284.8	8459.0 8295.6	0.0 0.0	0.0 8712.0	8163.9 8486.2	8312.2
Coal, MMBTU	569440.5 2810071.9	309979.2 3103012.4	336312.9 1488665.2	0.0 0.0	0.0 47846.3	611919.0 1055985.8	10333233.2
Oil, MMBTU	7759.0 0.0	6702.6 764.7	168.9 0.0	0.0 0.0	0.0 8649.5	10297.2 7859.0	42200.9
Gas, MMBTU	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0
Startup, MMBTU **	-5373.0 0.0	-5373.0 0.0	0.0 0.0	0.0 0.0	0.0 -5373.0	-5373.0 -5373.0	-26865.0
Total Fuel Consumption, MMBTU	571826.5 2810071.9	311308.8 3103777.1	336481.8 1488665.2	0.0 0.0	0.0 51122.8	616843.2 1058471.8	10348569.1
Net MWH Generation***	48697 243726	21627 283888	28499 129600	0 0	0 3827	49022 96003	904889
Average Net Operating Heat Rate	11743 11530	14394 10933	11807 11487	--- ---	--- 13358	12583 11025	11436

* Weighted average of daily as-burned BTU/Lb values.

** Based on number of unit starts after unit off-line 24 hours or more.

*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
 for January 2020 - December 2020

GCEC 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	134434.0 63420.0	192384.0 4238.0	90542.0 0.0	0.0 0.0	13296.0 0.0	21796.0 0.0	520110.0
BTU/Lb*	11304.8 11220.3	11435.8 10607.0	11350.2 0.0	0.0 0.0	11356.0 0.0	11217.9 0.0	11342.8
Coal, MMBTU	1519743.4 711591.9	2200059.6 44952.5	1027672.4 0.0	0.0 0.0	150989.4 0.0	244504.5 0.0	5899513.7
Oil, MMBTU	1782.9 515.1	3318.5 0.0	1109.4 0.0	0.0 0.0	673.6 0.0	586.3 0.0	7985.8
Gas, MMBTU	152383.2 635500.1	72173.9 697316.6	36354.1 0.0	0.0 0.0	36560.2 0.0	239526.9 0.0	1869815.1
Startup, MMBTU **	-2256.0 -2256.0	0.0 -2256.0	0.0 0.0	0.0 0.0	-2256.0 0.0	-2256.0 0.0	-11280.0
Total Fuel Consumption, MMBTU	1671653.5 1345351.1	2275552.0 740013.1	1065135.9 0.0	0.0 0.0	185967.2 0.0	482361.7 0.0	7766034.5
Net MWH Generation***	159111 116886	195727 60336	101709 0	0 0	5757 0	39029 0	678555
Average Net Operating Heat Rate	10506 11510	11626 12265	10472 ---	--- ---	32303 ---	12359 ---	11445

* Weighted average of daily as-burned BTU/Lb values.

** Based on number of unit starts after unit off-line 24 hours or more.

*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
 for January 2020 - December 2020

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	17882.0 191714.0	18290.0 239762.0	47074.0 161618.0	0.0 0.0	149180.0 0.0	177716.0 152632.0	1155868.0
BTU/Lb*	9427.2 8599.6	8661.5 8852.0	8689.1 8779.4	0.0 0.0	8919.7 0.0	8701.3 8849.3	8784.4
Coal, MMBTU	168576.7 1648667.1	158419.4 2122363.2	409028.6 1418906.2	0.0 0.0	1330640.1 0.0	1546357.4 1350692.5	10153651.2
Oil, MMBTU	4214.3 2910.7	4030.5 236.2	561.9 184.5	0.0 0.0	7095.3 0.0	37.7 4878.9	24150.0
Gas, MMBTU	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0
Startup, MMBTU **	-2388.7 -2388.7	-2388.7 0.0	0.0 0.0	0.0 0.0	-2388.7 0.0	0.0 -2388.7	-11943.5
Total Fuel Consumption, MMBTU	170402.3 1649189.1	160061.2 2122599.4	409590.5 1419090.7	0.0 0.0	1335346.7 0.0	1546395.1 1353182.7	10165857.7
Net MWH Generation***	14738 145663	12428 200851	37096 136068	0 0	116218 0	132069 121545	916676
Average Net Operating Heat Rate	11562 11322	12879 10568	11041 10429	--- ---	11490 ---	11709 11133	11090

* Weighted average of daily as-burned BTU/Lb values.

** Based on number of unit starts after unit off-line 24 hours or more.

*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
 for January 2020 - December 2020

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	67626.0 224498.0	60452.0 256208.0	138196.0 215896.0	0.0 196772.0	5760.0 206064.0	163492.0 198402.0	1733366.0
BTU/Lb*	8851.5 8610.9	8704.2 8846.6	8816.1 8775.8	0.0 9114.4	8958.0 8846.7	8696.4 8734.8	8803.9
Coal, MMBTU	598589.6 1933132.4	526186.5 2266578.3	1218348.9 1894650.7	0.0 1793459.0	51598.1 1822990.9	1421787.5 1733001.9	15260323.8
Oil, MMBTU	2643.5 174.6	5684.1 223.0	1764.0 973.4	0.0 3597.2	6348.1 749.6	2178.5 5676.1	30012.1
Gas, MMBTU	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0
Startup, MMBTU **	-2388.7 0.0	-2388.7 0.0	0.0 0.0	0.0 0.0	-2388.7 0.0	0.0 0.0	-7166.1
Total Fuel Consumption, MMBTU	598844.4 1933307.0	529481.9 2266801.3	1220112.9 1895624.1	0.0 1797056.2	55557.5 1823740.5	1423966.0 1738678.0	15283169.8
Net MWH Generation***	50508 174599	42867 219141	104934 178726	0 164146	3364 167254	124839 165761	1396139
Average Net Operating Heat Rate	11856 11073	12352 10344	11627 10606	--- 10948	16515 10904	11406 10489	10947

* Weighted average of daily as-burned BTU/Lb values.

** Based on number of unit starts after unit off-line 24 hours or more.

*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
 for January 2020 - December 2020

Smith 3

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0
BTU/Lb*	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0
Coal, MMBTU	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0
Oil, MMBTU	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0 0.0	0.0
Gas, MMBTU	3140397.0 3201198.0	2780623.0 3213153.0	2228019.0 2985482.0	2659416.0 3174824.0	3114947.0 3057526.0	3089787.0 2224335.0	34869707.0
Startup, MMBTU **	0.0 0.0	0.0 0.0	-2400.0 0.0	-1200.0 0.0	0.0 0.0	0.0 -1200.0	-4800.0
Total Fuel Consumption, MMBTU	3140397.0 3201198.0	2780623.0 3213153.0	2225619.0 2985482.0	2658216.0 3174824.0	3114947.0 3057526.0	3089787.0 2223135.0	34864907.0
Net MWH Generation***	453706 452041	400285 455509	317876 235913	380515 404428	443616 388629	435149 398370	4766037
Average Net Operating Heat Rate	6922 7082	6947 7054	7002 12655	6986 7850	7022 7867	7101 5581	7315

* Weighted average of daily as-burned BTU/Lb values.

** Based on number of unit starts after unit off-line 24 hours or more.

*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate
 for January 2020 - December 2020
 Adjusted to Target Basis Using Heat Rate
 Equations Filed September 3, 2019

Scherer 3

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	10626 10587	10489 10482	10391 10659	10792 10668	10672 10823	10613 10621	
2. Target Heat Rate at Actual Conditions**	11278 11605	11399 11130	11241 11706	10792 10668	10672 12063	11544 11699	
3. Adjustment to Actual Heat Rate (1-2)	-652 -1018	-910 -648	-850 -1047	0 0	0 -1240	-931 -1078	
4. Actual Heat Rate (Page 2 of Sched. 3)	11740 11530	14390 10933	11807 11487	0 0	0 13326	12580 11024	
5. Adjusted Actual Heat Rate (4+3)	11088 10512	13480 10285	10957 10440	0 0	0 12086	11649 9946	
6. Net MWH Generation	48697 243726	21627 283888	28499 129600	0 0	0 3827	49022 96003	
7. Adjusted Actual Heat Rate for January 2020 - December 2020 = $(\Sigma (5*6) / \Sigma 6)$							10555

* From pages 17 & 18, Schedule 3 of Exhibit to C. L. Nicholson's September 3, 2019 GPIF Testimony in Docket 20190001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2020 - December 2020
Adjusted to Target Basis Using Heat Rate
Equations Filed September 3, 2019

GCEC 7

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	10381 10637	10490 10639	10278 11195	10386 -	10461 10656	10597 11345	
2. Target Heat Rate at Actual Conditions**	10441 11025	10561 11630	10837 11195	10386 -	11358 10656	11492 11345	
3. Adjustment to Actual Heat Rate (1-2)	-60 -388	-71 -991	-559 0	0 0	-897 0	-895 0	
4. Actual Heat Rate (Page 3 of Sched. 3)	10506 11510	11626 12265	10472 0	0 0	32302 0	12359 0	
5. Adjusted Actual Heat Rate (4+3)	10446 11122	11555 11274	9913 0	0 0	31405 0	11464 0	
6. Net MWH Generation	159111 116886	195727 60336	101709 0	0 0	5757 0	39029 0	
7. Adjusted Actual Heat Rate for January 2020 - December 2020 = (Σ (5*6) / Σ 6)							11112

* From pages 19 & 20, Schedule 3 of Exhibit to C. L. Nicholson's September 3, 2019 GPIF Testimony in Docket 20190001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 13 of this Schedule.

Calculation of Average Net Operating Heat Rate
 for January 2020 - December 2020
 Adjusted to Target Basis Using Heat Rate
 Equations Filed September 3, 2019

Daniel 1

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	11880 11054	12044 11037	11851 10999	11786 -	11536 -	11265 -	
2. Target Heat Rate at Actual Conditions**	11724 11300	11782 10970	12274 11048	11786 -	11635 -	11644 11265	
3. Adjustment to Actual Heat Rate (1-2)	156 -246	262 67	-423 -49	0 0	-99 0	-379 139	
4. Actual Heat Rate (Page 4 of Sched. 3)	11557 11322	12874 10568	11041 10429	0 0	11489 0	11709 11133	
5. Adjusted Actual Heat Rate (4+3)	11713 11076	13136 10635	10618 10380	0 0	11390 0	11330 11272	
6. Net MWH Generation	14738 145663	12428 200851	37096 136068	0 0	116218 0	132069 121545	
7. Adjusted Actual Heat Rate for January 2020 - December 2020 = $(\Sigma (5*6) / \Sigma 6)$							10998

* From pages 21 & 22 , Schedule 3 of Exhibit to C. L. Nicholson's September 3, 2019 GPIF Testimony in Docket 20190001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 13 of this Schedule.

Calculation of Average Net Operating Heat Rate
 for January 2020 - December 2020
 Adjusted to Target Basis Using Heat Rate
 Equations Filed September 3, 2019

Daniel 2

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	11373 11039	10556 10857	- 10994	10955 11177	11056 -	11041 11453	
2. Target Heat Rate at Actual Conditions**	11914 11337	11327 10780	11269 11024	10955 11180	11459 11144	11715 10959	
3. Adjustment to Actual Heat Rate (1-2)	-541 -298	-771 77	-212 -30	0 -3	-403 -87	-674 494	
4. Actual Heat Rate (Page 5 of Sched. 3)	11856 11073	12350 10344	11627 10606	0 10948	16484 10904	11406 10489	
5. Adjusted Actual Heat Rate (4+3)	11315 10775	11579 10421	11415 10576	0 10945	16081 10817	10732 10983	
6. Net MWH Generation	50508 174599	42867 219141	104934 178726	0 164146	3364 167254	124839 165761	
7. Adjusted Actual Heat Rate for January 2020 - December 2020 = $(\Sigma (5*6) / \Sigma 6)$							10845

* From pages 23 & 24, Schedule 3 of Exhibit to C. L. Nicholson's September 3, 2019 GPIF Testimony in Docket 20190001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 13 of this Schedule.

Calculation of Average Net Operating Heat Rate
 for January 2020 - December 2020
 Adjusted to Target Basis Using Heat Rate
 Equations Filed September 3, 2019

Smith 3

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	6874 6994	6808 7022	6864 6951	6863 6763	6865 7044	6874 6872	
2. Target Heat Rate at Actual Conditions**	6862 6982	6807 7011	6865 6550	6868 6683	6865 6981	6867 7002	
3. Adjustment to Actual Heat Rate (1-2)	12 12	1 11	-1 401	-5 80	0 63	7 -130	
4. Actual Heat Rate*** (Page 6 of Sched. 3)	6922 7082	6947 7054	7002 6951	6986 6763	7022 7044	7101 6872	
5. Adjusted Actual Heat Rate (4+3)	6934 7094	6948 7065	7001 7352	6981 6843	7022 7107	7108 6742	
6. Net MWH Generation	453706 452041	400285 455509	317876 235913	380515 404428	443616 388629	435149 398370	
7. Adjusted Actual Heat Rate for January 2020 - December 2020 = $(\Sigma (5*6) / \Sigma 6)$							7006

* From pages 25 & 26, Schedule 3 of Exhibit to C. L. Nicholson's September 3, 2019 GPIF Testimony in Docket 20190001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 13 of this Schedule.

Actual Values of
 Target Heat Rate Equation Parameters
 for January 2020 - December 2020

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Scherer 3							
	+3						
	AKW * 10	349.1	282.2	307.7	0.0	0.0	331.7
		327.6	381.6	318.0	0.0	215.5	280.9
	+6						
	LSRF * 10	149965.0	83417.0	97694.8	0.0	0.0	137977.7
		125225.4	176388.6	117683.1	0.0	60589.8	84786.7
GCEC 7							
	+3						
	AKW * 10	315.2	281.2	251.1	0.0	183.6	211.1
		266.9	198.9	0.0	0.0	0.0	0.0
	+6						
	LSRF * 10	104216.4	82442.7	64508.3	0.0	47718.5	49039.5
		74265.6	40271.7	0.0	0.0	0.0	0.0
Daniel 1							
	+3						
	AKW * 10	200.7	173.6	174.5	0.0	183.7	183.4
		217.0	270.0	258.4	0.0	0.0	221.9
	+6						
	LSRF * 10	44020.2	31445.9	30704.3	0.0	34776.9	35099.7
		51619.3	83184.1	78588.5	0.0	0.0	54785.4
Daniel 2							
	+3						
	AKW * 10	160.2	117.9	146.9	0.0	164.5	174.1
		234.7	294.5	249.4	227.2	232.0	260.0
	+6						
	LSRF * 10	29095.7	26135.8	22590.6	0.0	35572.9	35128.4
		67476.1	105500.7	78902.8	67385.9	64792.2	82461.1
Smith 3							
	+3						
	AKW * 10	609.8	606.6	599.0	583.8	596.3	610.8
		607.6	612.2	327.7	543.6	539.0	778.9
	+6						
	LSRF * 10	374730.1	361709.8	362631.8	347427.4	360352.9	370937.3
		372914.0	376940.9	350907.0	370457.2	373767.9	360269.0

Target Heat Rate Equations

$$\begin{aligned}
 \text{Scherer 3 ANOHR} &= 10^6 / \text{AKW} * [606.47 - 82.01 * \text{FEB} - 83.21 * \text{MAR} + 61.89 * \text{APR} + 58.15 * \text{JUN} + 70.05 * \text{JUL} + 82.11 * \\
 &\quad \text{SEP} - 62.77 * \text{NOV}] \\
 &\quad + 9,540 \\
 \\
 \text{GCEC 7 ANOHR} &= 10^6 / \text{AKW} * [472.40 - 98.31 * \text{JAN} - 105.00 * \text{FEB} - 75.12 * \text{MAR} - 128.98 * \text{APR} - 86.23 * \text{MAY} - 72.19 * \\
 &\quad \text{OCT} - 155.88 * \text{NOV}] \\
 &\quad + 9,255 \\
 \\
 \text{Daniel 1 ANOHR} &= 10^6 / \text{AKW} * [513.64 + 53.71 * \text{JAN} + 90.24 * \text{MAR} - 77.10 * \text{OCT} - 78.86 * \text{NOV}] \\
 &\quad + 8,476 + 0.00192 * \text{LSRF} / \text{AKW} \\
 \\
 \text{Daniel 2 ANOHR} &= 10^6 / \text{AKW} * [398.23 - 174.36 * \text{FEB} - 127.75 * \text{MAR} - 64.08 * \text{MAY} + 49.83 * \text{JUL}] \\
 &\quad + 9,428 \\
 \\
 \text{Smith 3 ANOHR} &= 10^6 / \text{AKW} * [-105.54 - 40.39 * \text{FEB} + 72.63 * \text{JUL} + 91.40 * \text{AUG} + 46.84 * \text{SEP} - 61.62 * \text{OCT} + 104.67 * \text{NOV}] \\
 &\quad + 7,448 - 0.00067 * \text{LSRF} / \text{AKW}
 \end{aligned}$$

Where:	ANOHR	Average Net Operating Heat Rate, BTU/KWH
	AKW	Average Kilowatt Load, KW
	LSRF	Load Square Range Factor, KW^2
	JAN	January, 0 if not January, 1 if January
	FEB	February, 0 if not February, 1 if February
	MAR	March, 0 if not March, 1 if March
	APR	April, 0 if not April, 1 if April
	MAY	May, 0 if not May, 1 if May
	JUN	June, 0 if not June, 1 if June
	JUL	July, 0 if not July, 1 if July
	AUG	August, 0 if not August, 1 if August
	SEP	September, 0 if not September, 1 if September
	OCT	October, 0 if not October, 1 if October
	NOV	November, 0 if not November, 1 if November

Calculation of Heat Rate Points
 for January 2020 - December 2020

(1)	(2)	(3)	(4)	(5)
Unit	Actual Average Net Operating Heat Rate Target*	Net Operating Heat Rate Adjusted to Target Basis**	Minimum Attainable Heat Rate*	Heat Rate Points***
Scherer 3	10,616	10,555	10,298	0.00
GCEC 7	10,584	11,112	10,266	-10.00
Daniel 1	11,404	10,998	11,062	10.00
Daniel 2	11,057	10,845	10,725	5.33
Smith 3	6,900	7,006	6,693	-2.35

* From page 5, Schedule 3 of Exhibit to C. L. Nicholson's
 September 3, 2019 GPIF Testimony in Docket 20190001-EI.

** Refer to pages 7 through 11 of this Schedule for calculation.

*** If $[(2) - 75] \leq (3) \leq [(2) + 75]$ then points = 0

If $[(2) - (3) - 75] > 0$ then points = $\frac{(2) - (3) - 75}{(2) - (4) - 75} * 10$

If $[(2) - (3) + 75] < 0$ then points = $\frac{(2) - (3) + 75}{(2) - (4) - 75} * 10$

IV. CALCULATION OF COMPANY GPIF POINTS AND REWARD/PENALTY

Calculation of Heat Rate Points
 GPIF Points and Reward or Penalty
 for January 2020 - December 2020

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Scherer 3	-10.00	0.005	0.00	0.247
GCEC 7	-10.00	0.001	-10.00	0.074
Daniel 1	0.00	0.000	10.00	0.013
Daniel 2	-10.00	0.001	5.33	0.033
Smith 3	-10.00	0.013	-2.35	0.613

$$\begin{aligned}
 \text{Company GPIF Points} = & -10.00 * 0.005 + 0.00 * 0.247 \\
 & -10.00 * 0.001 - 10.00 * 0.074 \\
 & + 0.00 * 0.000 + 10.00 * 0.013 \\
 & -10.00 * 0.001 + 5.33 * 0.033 \\
 & -10.00 * 0.013 - 2.35 * 0.613
 \end{aligned}$$

$$= -2.08$$

$$\begin{aligned}
 \text{Company reward/penalty} = & -2.08 \text{ points} * \$789736 \text{ per point} \\
 = & (\$1,642,650)
 \end{aligned}$$

* From page 5, Schedule 3 of Exhibit to C. L. Nicholson's
 September 3, 2019 GPIF Testimony in Docket 20190001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2020 - DECEMBER 2020 PERIOD

CONTENTS	SCHEDULE 5 PAGE
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GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)	4
Calculation of System Actual GPIF Points	5
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GPIF Unit Performance Summary	11
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Planned Outage Schedules (Actual)	23

Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2020 - December 2020

Generating Performance Incentive Factor Points	Fuel Saving/Loss (\$000)	Generating Performance Incentive Factor (\$000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	4912	2456
+ 9	4421	2210
+ 8	3930	1965
+ 7	3438	1719
+ 6	2947	1474
+ 5	2456	1228
+ 4	1965	982
+ 3	1474	737
+ 2	982	491
+ 1	491	246
0	0	0
- 1	-502	-251
- 2	-1004	-502
- 3	-1506	-753
- 4	-2008	-1004
- 5	-2510	-1255
- 6	-3011	-1506
- 7	-3513	-1757
- 8	-4015	-2008
- 9	-4517	-2259
- 10	-5019	-2510
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Issued by: Gulf Power Company

Generating Performance Incentive Factor
 Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: January 2020 - December 2020

Line 1	Beginning of Period Balance of Common Equity	\$1,715,531,598
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '20	\$1,827,349,490
Line 3	Month of Feb '20	\$2,141,403,583
Line 4	Month of Mar '20	\$2,154,579,015
Line 5	Month of Apr '20	\$2,466,402,894
Line 6	Month of May '20	\$2,484,183,584
Line 7	Month of Jun '20	\$2,509,210,993
Line 8	Month of Jul '20	\$2,542,380,549
Line 9	Month of Aug '20	\$2,723,719,510
Line 10	Month of Sep '20	\$2,750,010,741
Line 11	Month of Oct '20	\$2,767,302,081
Line 12	Month of Nov '20	\$2,784,899,962
Line 13	Month of Dec '20	\$2,800,445,687
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	\$2,435,955,360
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	75.0562%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	\$8,113,771
Line 18	Jurisdictional Sales (KWH)	10,848,076,248
Line 19	Total Territorial Sales (KWH)	11,145,350,919
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	97.3327%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	\$7,897,357
Line 22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF point level from sheet 7.383.9)	\$2,456,000
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF Pt. level) (The lesser of Line 21 and Line 22)	\$2,456,000

Issued by: Gulf Power Company

Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2020 - December 2020

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Scherer 3	EAF3	0.5%	-10.00	-0.050
Scherer 3	ANOHR3	24.7%	0.00	0.000
GCEC 7	EAF4	0.1%	-10.00	-0.010
GCEC 7	ANOHR4	7.4%	-10.00	-0.740
Daniel 1	EAF5	0.0%	0.00	0.000
Daniel 1	ANOHR5	1.3%	10.00	0.130
Daniel 2	EAF6	0.1%	-10.00	-0.006
Daniel 2	ANOHR6	3.3%	5.33	0.176
Smith 3	EAF7	1.3%	-10.00	-0.134
Smith 3	ANOHR7	61.3%	-2.35	-1.441
Gulf Power GPIF Total		100.0%		-2.08

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2020 - December 2020

Scherer 3

Equivalent Availability Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Heat Rate
+ 10	23	97.80	+ 10	1,211	10,298
+ 9	21	97.70	+ 9	1,090	10,322
+ 8	18	97.60	+ 8	969	10,347
+ 7	16	97.50	+ 7	848	10,371
+ 6	14	97.40	+ 6	727	10,395
+ 5	12	97.30	+ 5	606	10,420
+ 4	9	97.20	+ 4	484	10,444
+ 3	7	97.10	+ 3	363	10,468
+ 2	5	97.00	+ 2	242	10,492
+ 1	2	96.90	+ 1	121	10,517
				0	10,541
0	0	96.80	0	0	10,616
				0	10,691
- 1	(4)	96.67	- 1	(121)	10,715
- 2	(7)	96.54	- 2	(242)	10,740
- 3	(11)	96.41	- 3	(363)	10,764
- 4	(14)	96.28	- 4	(484)	10,788
- 5	(18)	96.15	- 5	(606)	10,813
- 6	(21)	96.02	- 6	(727)	10,837
- 7	(25)	95.89	- 7	(848)	10,861
- 8	(28)	95.76	- 8	(969)	10,885
- 9	(32)	95.63	- 9	(1,090)	10,910
- 10	(35)	95.50	- 10	(1,211)	10,934
Weighting Factor:		0.005	Weighting Factor:		0.247

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2020 - December 2020

GCEC 7

Equivalent Availability Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Heat Rate
+ 10	4	80.90	+ 10	365	10,266
+ 9	4	80.65	+ 9	329	10,290
+ 8	3	80.40	+ 8	292	10,315
+ 7	3	80.15	+ 7	256	10,339
+ 6	2	79.90	+ 6	219	10,363
+ 5	2	79.65	+ 5	183	10,388
+ 4	2	79.40	+ 4	146	10,412
+ 3	1	79.15	+ 3	110	10,436
+ 2	1	78.90	+ 2	73	10,460
+ 1	0	78.65	+ 1	37	10,485
				0	10,509
0	0	78.40	0	0	10,584
				0	10,659
- 1	(1)	78.10	- 1	(37)	10,683
- 2	(1)	77.80	- 2	(73)	10,708
- 3	(2)	77.50	- 3	(110)	10,732
- 4	(2)	77.20	- 4	(146)	10,756
- 5	(3)	76.90	- 5	(183)	10,781
- 6	(3)	76.60	- 6	(219)	10,805
- 7	(4)	76.30	- 7	(256)	10,829
- 8	(4)	76.00	- 8	(292)	10,853
- 9	(5)	75.70	- 9	(329)	10,878
- 10	(5)	75.40	- 10	(365)	10,902
Weighting Factor:		0.001	Weighting Factor:		0.074

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2020 - December 2020

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Heat Rate
+ 10	1	73.80	+ 10	64	11,062
+ 9	1	73.51	+ 9	58	11,089
+ 8	1	73.22	+ 8	51	11,115
+ 7	1	72.93	+ 7	45	11,142
+ 6	1	72.64	+ 6	38	11,169
+ 5	1	72.35	+ 5	32	11,196
+ 4	0	72.06	+ 4	26	11,222
+ 3	0	71.77	+ 3	19	11,249
+ 2	0	71.48	+ 2	13	11,276
+ 1	0	71.19	+ 1	6	11,302
				0	11,329
0	0	70.90	0	0	11,404
				0	11,479
- 1	(0)	70.90	- 1	(6)	11,506
- 2	(0)	70.90	- 2	(13)	11,532
- 3	(1)	70.90	- 3	(19)	11,559
- 4	(1)	70.90	- 4	(26)	11,586
- 5	(1)	70.90	- 5	(32)	11,613
- 6	(1)	70.90	- 6	(38)	11,639
- 7	(1)	70.90	- 7	(45)	11,666
- 8	(2)	70.90	- 8	(51)	11,693
- 9	(2)	70.90	- 9	(58)	11,719
- 10	(2)	70.90	- 10	(64)	11,746
Weighting Factor:		0.000	Weighting Factor:		0.013

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2020 - December 2020

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Heat Rate
+ 10	3	86.50	+ 10	164	10,725
+ 9	3	86.32	+ 9	148	10,751
+ 8	2	86.14	+ 8	131	10,776
+ 7	2	85.96	+ 7	115	10,802
+ 6	2	85.78	+ 6	98	10,828
+ 5	2	85.60	+ 5	82	10,854
+ 4	1	85.42	+ 4	66	10,879
+ 3	1	85.24	+ 3	49	10,905
+ 2	1	85.06	+ 2	33	10,931
+ 1	0	84.88	+ 1	16	10,956
				0	10,982
0	0	84.70	0	0	11,057
				0	11,132
- 1	(0)	84.52	- 1	(16)	11,158
- 2	(1)	84.34	- 2	(33)	11,183
- 3	(1)	84.16	- 3	(49)	11,209
- 4	(2)	83.98	- 4	(66)	11,235
- 5	(2)	83.80	- 5	(82)	11,261
- 6	(2)	83.62	- 6	(98)	11,286
- 7	(3)	83.44	- 7	(115)	11,312
- 8	(3)	83.26	- 8	(131)	11,338
- 9	(4)	83.08	- 9	(148)	11,363
- 10	(4)	82.90	- 10	(164)	11,389
Weighting Factor:		0.001	Weighting Factor:		0.033

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2020 - December 2020

Smith 3

Equivalent Availability Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss (\$000)	Adjusted Actual Heat Rate
+ 10	66	90.80	+ 10	3,011	6,693
+ 9	59	90.71	+ 9	2,710	6,706
+ 8	53	90.62	+ 8	2,409	6,719
+ 7	46	90.53	+ 7	2,108	6,733
+ 6	40	90.44	+ 6	1,807	6,746
+ 5	33	90.35	+ 5	1,506	6,759
+ 4	26	90.26	+ 4	1,204	6,772
+ 3	20	90.17	+ 3	903	6,785
+ 2	13	90.08	+ 2	602	6,799
+ 1	7	89.99	+ 1	301	6,812
				0	6,825
0	0	89.90	0	0	6,900
				0	6,975
- 1	(16)	89.74	- 1	(301)	6,988
- 2	(32)	89.58	- 2	(602)	7,001
- 3	(47)	89.42	- 3	(903)	7,015
- 4	(63)	89.26	- 4	(1,204)	7,028
- 5	(79)	89.10	- 5	(1,506)	7,041
- 6	(95)	88.94	- 6	(1,807)	7,054
- 7	(111)	88.78	- 7	(2,108)	7,067
- 8	(126)	88.62	- 8	(2,409)	7,081
- 9	(142)	88.46	- 9	(2,710)	7,094
- 10	(158)	88.30	- 10	(3,011)	7,107
Weighting Factor:		0.013	Weighting Factor:		0.613

Issued by: Gulf Power Company

GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2020 - December 2020

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range		Max Fuel Savings (\$000)	Max Fuel Loss (\$000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss (\$000)
			Max %	Min %				
Scherer 3	0.5	96.8	97.8	95.5	\$23	(\$35)	92.0	(\$35)
GCEC 7	0.1	78.4	80.9	75.4	\$4	(\$5)	49.2	(\$5)
Daniel 1	0.0	70.9	73.8	70.9	\$1	(\$2)	68.7	\$0
Daniel 2	0.1	84.7	86.5	82.9	\$3	(\$4)	79.2	(\$4)
Smith 3	1.3	89.9	90.8	88.3	\$66	(\$158)	87.5	(\$158)

Total: 2.0

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range		Max Fuel Savings (\$000)	Max Fuel Loss (\$000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss (\$000)
				Max BTU/KWH	Min BTU/KWH				
Scherer 3	24.7	10,616	66.2	10,934	10,298	\$1,211	(\$1,211)	10,555	\$0
GCEC 7	7.4	10,584	64.7	10,902	10,266	\$365	(\$365)	11,112	(\$365)
Daniel 1	1.3	11,404	42.5	11,746	11,062	\$64	(\$64)	10,998	\$64
Daniel 2	3.3	11,057	47.5	11,389	10,725	\$164	(\$164)	10,845	\$87
Smith 3	61.3	6,900	93.7	7,107	6,693	\$3,011	(\$3,011)	7,006	(\$708)

Total: 98.0

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Actual Unit Performance Data

Gulf Power Company

Period of: January 2020 - December 2020

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
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Scherer 3	97.0	-5.0	92.0
GCEC 7	36.1	13.1	49.2
Daniel 1	72.0	-3.3	68.7
Daniel 2	70.5	8.7	79.2
Smith 3	93.6	-6.1	87.5

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
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Scherer 3	11,436	-881	10,555
GCEC 7	11,445	-333	11,112
Daniel 1	11,089	-91	10,998
Daniel 2	10,946	-101	10,845
Smith 3	6,981	25	7,006

* Refer to pages 3 through 7, Schedule 2.

** Refer to pages 7 through 11, Schedule 3.

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	SCHERER 3	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20	
1.	EAF (%)	100.0	100.0	100.0	100.0	100.0	96.7	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	139.5	76.7	92.6	0.0	0.0	147.8	
4.	RSH	604.5	619.4	650.4	720.0	744.0	548.1	
5.	UH	0.0	0.0	0.0	0.0	0.0	24.1	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	24.1	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	
14.	Oper MBtu	571,716	311,213	336,479	0	0	616,697	
15.	Net Gen (MWH)	48,697	21,627	28,499	0	0	49,022	
16.	ANOHR (Btu/KWH)	11,740	14,390	11,807	0	0	12,580	
17.	NOF %	40.4	32.6	35.6	0.0	0.0	38.3	
18.	NPC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	
19.	ANOHR Equation	$10^6 / AKW * [606.47 - 82.01 * FEB - 83.21 * MAR + 61.89 * APR + 58.15 * JUN + 70.05 * JUL + 82.11 * SEP - 62.77 * NOV] + 9,540$						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	SCHERER 3	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1.	EAF (%)	99.4	100.0	100.0	100.0	67.7	100.0	97.0
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	744.0	744.0	407.6	0.0	17.8	341.7	2711.7
4.	RSH	0.0	0.0	312.4	744.0	470.2	402.3	5815.3
5.	UH	0.0	0.0	0.0	0.0	233.0	0.0	257.1
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	24.1
8.	MOH	0.0	0.0	0.0	0.0	233.0	0.0	233.0
9.	PFOH	11.8	0.0	0.0	0.0	0.0	0.0	11.8
10.	LR pf (MW)	310.0	0.0	0.0	0.0	0.0	0.0	310.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	865.0
14.	Oper MBtu	2,810,072	3,103,766	1,488,665	0	51,000	1,058,360	10,347,968
15.	Net Gen (MWH)	243,726	283,888	129,600	0	3,827	96,003	904,889
16.	ANOHR (Btu/KWH)	11,530	10,933	11,487	0	13,326	11,024	11,436
17.	NOF %	37.9	44.1	36.8	0.0	24.9	32.5	38.6
18.	NPC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	865.0
19.	ANOHR Equation	$10^6 / AKW * [606.47 - 82.01 * FEB - 83.21 * MAR + 61.89 * APR + 58.15 * JUN + 70.05 * JUL + 82.11 * SEP - 62.77 * NOV] + 9,540$						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	GCEC 7	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20	
1.	EAf (%)	100.0	100.0	55.6	0.0	4.2	23.7	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	504.8	696.0	405.1	0.0	31.4	184.9	
4.	RSH	239.2	0.0	8.3	0.0	0.0	0.0	
5.	UH	0.0	0.0	329.6	720.0	712.6	535.1	
6.	POH	0.0	0.0	264.0	720.0	705.2	0.0	
7.	FOH	0.0	0.0	0.0	0.0	7.4	0.0	
8.	MOH	0.0	0.0	65.6	0.0	0.0	535.1	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	67.3	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	101.3	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	
14.	Oper MBtu	1,671,635	2,275,518	1,065,125	0	185,960	482,356	
15.	Net Gen (MWH)	159,111	195,727	101,709	0	5,757	39,029	
16.	ANOHR (Btu/KWH)	10,506	11,626	10,472	0	32,302	12,359	
17.	NOF %	66.4	59.2	52.9	0.0	38.6	44.4	
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	
19.	ANOHR Equation	$10^6 / AKW * [472.40 - 98.31 * JAN - 105.00 * FEB - 75.12 * MAR - 128.98 * APR - 86.23 * MAY - 72.19 * OCT - 155.88 * NOV] + 9,255$						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	GCEC 7	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1.	EAF (%)	58.9	44.7	48.3	0.0	0.0	0.0	36.1
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	438.0	303.3	0.0	0.0	0.0	0.0	2563.4
4.	RSH	1.0	87.3	348.0	0.0	0.0	0.0	683.7
5.	UH	305.0	353.4	372.0	744.0	721.0	744.0	5536.8
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1689.3
7.	FOH	0.0	2.1	358.0	744.0	721.0	744.0	2576.5
8.	MOH	305.0	351.3	14.0	0.0	0.0	0.0	1271.1
9.	PFOH	2.4	0.0	0.0	0.0	0.0	0.0	69.7
10.	LR pf (MW)	201.0	0.0	0.0	0.0	0.0	0.0	104.7
11.	PMOH	0.0	302.8	0.0	0.0	0.0	0.0	302.8
12.	LR pm (MW)	0.0	91.0	0.0	0.0	0.0	0.0	91.0
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0
14.	Oper MBtu	1,345,346	740,013	0	0	0	0	7,765,953
15.	Net Gen (MWH)	116,886	60,336	0	0	0	0	678,555
16.	ANOHR (Btu/KWH)	11,510	12,265	0	0	0	0	11,445
17.	NOF %	56.2	41.9	0.0	0.0	0.0	0.0	55.7
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0
19.	ANOHR Equation	10^6 / AKW * [472.40 - 98.31 * JAN - 105.00 * FEB - 75.12 * MAR - 128.98 * APR - 86.23 * MAY - 72.19 * OCT - 155.88 * NOV] + 9,255						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	DANIEL 1	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20	
1.	EAf (%)	98.5	98.4	98.6	88.3	82.9	84.7	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	73.4	71.6	212.6	0.0	632.8	720.0	
4.	RSH	670.6	624.4	530.4	636.0	80.6	0.0	
5.	UH	0.0	0.0	0.0	84.0	30.7	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	1.3	0.0	
8.	MOH	0.0	0.0	0.0	84.0	29.4	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	73.4	71.6	69.2	0.0	632.0	720.0	
12.	LR pm (MW)	77.0	77.0	77.0	0.0	77.0	77.0	
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
14.	Oper MBtu	170,333	159,995	409,581	0	1,335,230	1,546,394	
15.	Net Gen (MWH)	14,738	12,428	37,096	0	116,218	132,069	
16.	ANOHR (Btu/KWH)	11,557	12,874	11,041	0	11,489	11,709	
17.	NOF %	40.0	34.6	34.8	0.0	36.6	36.5	
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
19.	ANOHR Equation	$10^6 / AKW * [513.64 + 53.71 * JAN + 90.24 * MAR - 77.10 * OCT - 78.86 * NOV]$ $+ 8,476 + 0.00192 * LSRF / AKW$						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	DANIEL 1	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1.	EAF (%)	86.5	90.6	74.0	0.0	0.0	62.3	72.0
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	671.3	744.0	526.6	0.0	0.0	547.7	4200.0
4.	RSH	60.5	0.0	73.4	0.0	0.0	0.0	2675.8
5.	UH	12.2	0.0	120.0	744.0	721.0	196.3	1908.2
6.	POH	0.0	0.0	120.0	744.0	721.0	196.3	1781.3
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	1.3
8.	MOH	12.2	0.0	0.0	0.0	0.0	0.0	125.6
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11.	PMOH	572.9	454.9	438.0	0.0	0.0	547.5	3579.4
12.	LR pm (MW)	77.0	77.0	77.0	0.0	0.0	77.0	77.0
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
14.	Oper MBtu	1,649,141	2,122,595	1,419,087	0	0	1,353,102	10,165,459
15.	Net Gen (MWH)	145,663	200,851	136,068	0	0	121,545	916,676
16.	ANOHR (Btu/KWH)	11,322	10,568	10,429	0	0	11,133	11,089
17.	NOF %	43.2	53.8	51.5	0.0	0.0	44.2	43.5
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
19.	ANOHR Equation	$10^6 / AKW * [513.64 + 53.71 * JAN + 90.24 * MAR - 77.10 * OCT - 78.86 * NOV]$ $+ 8,476 + 0.00192 * LSRF / AKW$						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	DANIEL 2	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20	
1.	EAf (%)	69.3	87.7	81.4	0.0	2.3	86.1	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	315.3	363.5	714.3	0.0	20.5	717.0	
4.	RSH	309.2	326.0	0.0	0.0	0.0	0.0	
5.	UH	119.6	6.5	28.7	720.0	723.6	3.0	
6.	POH	0.0	0.0	26.3	720.0	723.6	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	3.0	
8.	MOH	119.6	6.5	2.4	0.0	0.0	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	314.7	363.1	714.9	0.0	20.1	630.9	
12.	LR pm (MW)	173.0	109.4	77.0	0.0	77.0	77.0	
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
14.	Oper MBtu	598,801	529,388	1,220,084	0	55,453	1,423,930	
15.	Net Gen (MWH)	50,508	42,867	104,934	0	3,364	124,839	
16.	ANOHR (Btu/KWH)	11,856	12,350	11,627	0	16,484	11,406	
17.	NOF %	31.9	23.5	29.3	0.0	32.8	34.7	
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
19.	ANOHR Equation	$10^6 / AKW * [398.23 - 174.36 * FEB - 127.75 * MAR - 64.08 * MAY + 49.83 * JUL]$ + 9,428						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	DANIEL 2	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1.	EAF (%)	88.5	90.7	86.1	82.2	84.7	86.9	70.5
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	744.0	744.0	716.7	722.6	721.0	637.5	6416.2
4.	RSH	0.0	0.0	0.0	0.0	0.0	106.5	741.7
5.	UH	0.0	0.0	3.3	21.4	0.0	0.0	1626.1
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1469.9
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	3.0
8.	MOH	0.0	0.0	3.3	21.4	0.0	0.0	153.2
9.	PFOH	5.5	0.0	0.0	0.0	0.0	0.0	5.5
10.	LR pf (MW)	117.0	0.0	0.0	0.0	0.0	0.0	117.0
11.	PMOH	550.0	452.9	629.6	722.2	721.0	637.1	5756.4
12.	LR pm (MW)	77.0	77.0	77.0	77.0	77.0	77.0	84.3
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
14.	Oper MBtu	1,933,304	2,266,798	1,895,608	1,796,997	1,823,728	1,738,584	15,282,675
15.	Net Gen (MWH)	174,599	219,141	178,726	164,146	167,254	165,761	1,396,139
16.	ANOHR (Btu/KWH)	11,073	10,344	10,606	10,948	10,904	10,489	10,946
17.	NOF %	46.7	58.7	49.7	45.3	46.2	51.8	43.3
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
19.	ANOHR Equation	$10^6 / AKW * [398.23 - 174.36 * FEB - 127.75 * MAR - 64.08 * MAY + 49.83 * JUL]$ $+ 9,428$						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	SMITH 3	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20	
1.	EAf (%)	100.0	94.8	71.4	90.2	100.0	98.8	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	744.0	659.9	530.7	651.8	744.0	712.5	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	36.1	212.3	68.2	0.0	7.5	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	14.3	0.0	0.0	0.0	
8.	MOH	0.0	36.1	198.0	68.2	0.0	7.5	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	4.5	0.0	7.5	
12.	LR pm (MW)	0.0	0.0	0.0	332.0	0.0	117.0	
13.	NSC (MW)	646.3	646.3	636.0	636.0	636.0	627.2	
14.	Oper MBtu	3,140,397	2,780,623	2,225,619	2,658,216	3,114,947	3,089,787	
15.	Net Gen (MWH)	453,706	400,285	317,876	380,515	443,616	435,149	
16.	ANOHR (Btu/KWH)	6,922	6,947	7,002	6,986	7,022	7,101	
17.	NOF %	94.4	93.9	94.2	91.8	93.8	97.4	
18.	NPC (MW)	646.3	646.3	636.0	636.0	636.0	627.2	
19.	ANOHR Equation	$10^6 / AKW * [-105.54 - 40.39 * FEB + 72.63 * JUL + 91.40 * AUG + 46.84 * SEP - 61.62 * OCT + 104.67 * NOV]$ $+ 7,448 - 0.00067 * LSRF / AKW$						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	SMITH 3	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1.	EAF (%)	100.0	100.0	99.7	100.0	100.0	68.7	93.6
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	744.0	744.0	720.0	744.0	721.0	511.5	8227.3
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	0.0	0.0	0.0	232.5	556.7
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	14.3
8.	MOH	0.0	0.0	0.0	0.0	0.0	232.5	542.4
9.	PFOH	0.0	0.0	13.3	0.0	0.0	0.0	13.3
10.	LR pf (MW)	0.0	0.0	117.0	0.0	0.0	0.0	117.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	12.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	197.2
13.	NSC (MW)	627.2	627.2	627.2	636.0	636.0	646.3	635.6
14.	Oper MBtu	3,201,198	3,213,153	1,639,831	2,735,145	2,737,505	2,737,597	33,274,018
15.	Net Gen (MWH)	452,041	455,509	235,913	404,428	388,629	398,370	4,766,037
16.	ANOHr (Btu/KWH)	7,082	7,054	6,951	6,763	7,044	6,872	6,981
17.	NOF %	96.9	97.6	52.2	85.5	84.8	120.5	91.1
18.	NPC (MW)	627.2	627.2	627.2	636.0	636.0	646.3	635.6
19.	ANOHr Equation	$10^6 / AKW * [-105.54 - 40.39 * FEB + 72.63 * JUL + 91.40 * AUG + 46.84 * SEP - 61.62 * OCT + 104.67 * NOV]$ $+ 7,448 - 0.00067 * LSRF / AKW$						

Docket No. 20210001-EI
GPIF 2020 Results Filing
Exhibit CCR-2, Page 52 of 52
Schedule 5
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Original Sheet No. 7.385.9

Planned Outage Schedules (Actual)

Period of: January 2020 - December 2020

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

Issued by: Gulf Power Company

WITNESS: CHARLES R. ROTE

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2022

SEPTEMBER 3, 2021

CRR-2
DOCKET NO. 20210001-EI
FPL Witness: Charles R. Rote
Exhibit No.: _____
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EXHIBIT INDEX**CONSOLIDATED FLORIDA POWER & LIGHT COMPANY****JANUARY THROUGH DECEMBER, 2022**

<u>EXHIBIT</u>	<u>PAGE NUMBER</u>	<u>TITLE</u>
CRR-2	7.201.001	Exhibit Index
	7.201.002	Projected System Generation
	7.201.003	Units Used to Determine GPIF
	7.201.004	GPIF Reward/Penalty Table (Estimated)
	7.201.005	GPIF Calculation of Maximum Allowed Incentive Dollars (Estimated)
	7.201.006 and 7.201.007	GPIF Target and Range Summary
	7.201.008	GPIF Projected Unit Heat Rate Equations
	7.201.009	Derivation of Weighting Factors
	7.201.010 - 7.201.024	Estimated Unit Performance Data
	7.201.025 - 7.201.039	Unit FOF and MOF vs Time Graphs
	7.201.040	Planned Outages Schedule (Estimated)

**Consolidated Florida Power & Light Projected System Generation
January Through December, 2022**

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost (\$000)
Okeechobee	1,603	8,424	10,254,817	75.9	7.7	7.7	230,813
Ft. Myers 2	1,700	8,760	9,113,274	61.2	6.8	14.5	229,074
Port Everglades 5	1,254	7,920	8,654,182	87.1	6.5	21.0	196,595
St. Lucie 1	981	8,040	7,767,681	98.5	5.8	26.8	38,478
St. Lucie 2	840	8,760	7,243,187	98.4	5.4	32.2	32,167
Turkey Point 3	837	8,760	7,226,588	98.6	5.4	37.7	38,368
Manatee 3	1,235	7,854	6,783,951	69.9	5.1	42.7	160,153
Turkey Point 4	844	8,064	6,703,465	98.5	5.0	47.8	38,527
West County 3	1,228	8,520	6,591,962	63.0	4.9	52.7	153,766
Riviera 5	1,308	8,520	6,181,036	55.5	4.6	57.3	146,576
Turkey Point 5	1,256	7,685	5,700,436	59.1	4.3	61.6	139,845
Martin 8	1,224	6,714	5,777,852	70.3	4.3	65.9	132,100
West County 2	1,223	7,080	5,247,984	60.6	3.9	69.9	120,068
Sanford 5	1,147	8,520	5,104,412	52.2	3.8	73.7	126,609
Dania Beach	1,182	5,112	4,926,686	81.5	3.7	77.4	103,281
Cape Canaveral 3	1,308	8,520	4,747,216	42.6	3.6	80.9	113,885
West County 1	1,223	6,101	4,389,266	58.8	3.3	84.2	102,149
GP Lansing Smith CC	696	6,759	3,685,572	78.4	2.8	87.0	93,959
Sanford 4	1,147	5,161	3,265,562	55.2	2.4	89.4	78,999
Martin 3	464	6,387	1,500,672	50.6	1.1	90.5	38,326
Martin 4	464	4,704	1,168,290	53.5	0.9	91.4	28,422
GP Daniel 2	502	4,013	814,593	40.4	0.6	92.0	22,027
GP Daniel 1	502	3,930	759,289	38.5	0.6	92.6	20,778
GP Crist 6	315	3,550	499,707	44.7	0.4	93.0	19,872
GP Crist 7	496	1,551	296,648	38.6	0.2	93.2	12,452
Southfork PV Solar	75	4,502	203,036	60.5	0.2	93.3	0
Echo River PV Solar	75	4,655	198,396	57.2	0.1	93.5	0
GP Blue Indigo PV Solar	26	4,625	189,694	155.8	0.1	93.6	0
Horizon PV Solar	75	4,502	183,041	54.6	0.1	93.8	0
Coral Farms PV Solar	75	4,474	182,310	54.7	0.1	93.9	0
Hammock PV Solar	75	4,502	181,818	54.2	0.1	94.0	0
Wildflower PV Solar	75	4,502	181,544	54.1	0.1	94.2	0
Loggerhead PV Solar	75	4,474	178,701	53.6	0.1	94.3	0
Blue Cypress PV Solar	75	4,474	177,362	53.2	0.1	94.4	0
Cattle Ranch PV Solar	75	4,594	177,284	51.8	0.1	94.6	0
Indian River PV Solar	75	4,474	177,229	53.2	0.1	94.7	0
Babcock Preserve PV Solar	75	4,502	177,036	52.8	0.1	94.8	0
Blue Heron PV Solar	75	4,502	177,036	52.8	0.1	95.0	0
FPL Elder Branch PV Solar	75	4,161	176,859	57.1	0.1	95.1	0
Okeechobee PV Solar	75	4,474	176,734	53.0	0.1	95.2	0
Twin Lakes PV Solar	75	4,594	172,519	50.4	0.1	95.4	0
Barefoot Bay PV Solar	75	4,474	172,335	51.7	0.1	95.5	0
Interstate PV Solar	75	4,474	171,862	51.6	0.1	95.6	0
Sunshine Gateway PV Solar	75	4,532	171,666	50.8	0.1	95.8	0
Miami-Dade PV Solar	75	4,474	171,187	51.4	0.1	95.9	0
Hibiscus PV Solar	75	4,474	170,974	51.3	0.1	96.0	0
GP Scherer 3	860	1,721	169,429	11.4	0.1	96.1	4,993
Manatee PV Solar	75	4,809	168,695	47.1	0.1	96.3	0
Citrus PV Solar	75	4,778	167,642	47.1	0.1	96.4	0
Pioneer Trail PV Solar	75	4,474	167,568	50.3	0.1	96.5	0
Babcock PV Solar	75	4,840	166,050	46.1	0.1	96.6	0
Willow PV Solar	75	4,594	160,735	47.0	0.1	96.8	0
Rodeo PV Solar	75	4,563	160,017	47.1	0.1	96.9	0
Sweet Bay PV Solar	75	4,504	156,670	46.7	0.1	97.0	0
Trailside PV Solar	75	4,655	156,455	45.1	0.1	97.1	0
GP Cotton Creek PV Solar	22	4,502	156,274	157.4	0.1	97.2	0
Lakeside PV Solar	75	4,502	156,175	46.6	0.1	97.4	0
Union Springs PV Solar	75	4,624	155,693	45.2	0.1	97.5	0
Sabal Palm PV Solar	75	4,474	154,947	46.5	0.1	97.6	0
Magnolia Springs PV Solar	75	4,624	153,932	44.7	0.1	97.7	0
Northern Preserve PV Solar	75	4,502	153,872	45.9	0.1	97.8	0
Orange Blossom PV Solar	75	4,474	153,342	46.0	0.1	97.9	0
Pelican PV Solar	75	4,474	153,342	46.0	0.1	98.0	0
GP Blue Springs PV Solar	21	4,656	152,361	157.3	0.1	98.2	0
FPL Immokalee PV Solar	75	4,133	151,934	49.3	0.1	98.3	0
Palm Bay PV Solar	75	4,474	151,794	45.5	0.1	98.4	0
FPL Ghost Orchid PV Solar	75	4,163	149,881	48.3	0.1	98.5	0
FPL Sawgrass PV Solar	75	4,163	149,431	48.2	0.1	98.6	0
FPL Grove PV Solar	75	4,194	148,153	47.4	0.1	98.7	0
FPL Sundew PV Solar	75	4,194	147,958	47.4	0.1	98.8	0
Egret PV Solar	75	4,655	147,922	42.7	0.1	98.9	0
Nassau PV Solar	75	4,655	142,776	41.2	0.1	99.1	0
Discovery PV Solar	75	4,502	141,637	42.2	0.1	99.2	0
Fort Drum PV Solar	75	4,474	140,874	42.3	0.1	99.3	0
GP Crist CT 1	235	634	138,754	93.3	0.1	99.4	4,622
GP Crist CT 2	235	578	126,933	93.6	0.1	99.5	4,235
GP Crist CT 3	235	551	122,030	94.4	0.1	99.6	4,077
GP Crist CT 4	235	525	111,559	90.6	0.1	99.6	3,794
GP Crist 4	78	1,525	61,021	51.3	0.0	99.7	2,661
GP Crist 5	78	1,367	54,939	51.5	0.0	99.7	2,443
Ft. Myers 3C	219	258	50,867	90.0	0.0	99.8	2,009
Desoto Solar	25	4,686	47,955	40.9	0.0	99.8	0
Ft. Myers 3D	219	243	47,789	89.8	0.0	99.8	1,911
GP Pea Ridge 1-3	8	4,200	33,701	100.3	0.0	99.9	1,902
Lauderdale 6A	216	154	28,265	85.0	0.0	99.9	1,059
Lauderdale 6B	216	151	27,877	85.5	0.0	99.9	1,055
Lauderdale 6C	216	144	25,724	82.7	0.0	99.9	969
GP Perdido 1-2	3	8,499	24,851	97.5	0.0	99.9	814
Lauderdale 6D	216	117	22,644	89.6	0.0	100.0	833
Lauderdale 6E	216	114	21,685	88.1	0.0	100.0	806
Space Coast Solar	10	4,808	17,396	36.2	0.0	100.0	0
Ft. Myers 3B	166	64	9,904	93.2	0.0	100.0	558
Ft. Myers 3A	162	58	9,033	96.1	0.0	100.0	626
GP Lansing Smith A	32	-	-	0.0	0.0	100.0	0
Total	32,278		133,491,438	100.0			2,456,657

Issued by: Florida Power & Light Company

CRR-2
DOCKET NO. 20210001-EI
FPL Witness: Charles R. Rote
Exhibit No. _____
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**UNITS TO BE USED TO DETERMINE THE
GENERATING PERFORMANCE INCENTIVE FACTOR
CONSOLIDATED FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2022**

Cape Canaveral 3

Ft. Myers 2

Manatee 3

Martin 8

Port Everglades 5

Riviera 5

Sanford 5

St. Lucie 1

St. Lucie 2

Turkey Point 3

Turkey Point 4

Turkey Point 5

West County 1

West County 2

West County 3

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

CONSOLIDATED FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2022

Generating Performance Incentive Points <u>(GPIF)</u>	Fuel Savings/(Loss) <u>(\$000)</u>	Generating Performance Incentive Factor <u>(\$000)</u>
+ 10	51,818	25,909
+ 9	46,636	23,318
+ 8	41,454	20,727
+ 7	36,273	18,136
+ 6	31,091	15,545
+ 5	25,909	12,955
+ 4	20,727	10,364
+ 3	15,545	7,773
+ 2	10,364	5,182
+ 1	5,182	2,591
0	0	0
- 1	(5,182)	(2,591)
- 2	(10,364)	(5,182)
- 3	(15,545)	(7,773)
- 4	(20,727)	(10,364)
- 5	(25,909)	(12,955)
- 6	(31,091)	(15,545)
- 7	(36,273)	(18,136)
- 8	(41,454)	(20,727)
- 9	(46,636)	(23,318)
- 10	(51,818)	(25,909)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS (ESTIMATED)

CONSOLIDATED FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY		\$	27,534,711,853
	END OF MONTH BALANCE OF COMMON EQUITY			
LINE 2	MONTH OF JANUARY	2022	\$	29,218,508,470
LINE 3	MONTH OF FEBRUARY	2022	\$	29,467,616,696
LINE 4	MONTH OF MARCH	2022	\$	29,814,247,397
LINE 5	MONTH OF APRIL	2022	\$	29,991,559,583
LINE 6	MONTH OF MAY	2022	\$	30,300,512,568
LINE 7	MONTH OF JUNE	2022	\$	30,733,200,823
LINE 8	MONTH OF JULY	2022	\$	31,126,662,172
LINE 9	MONTH OF AUGUST	2022	\$	33,665,483,922
LINE 10	MONTH OF SEPTEMBER	2022	\$	33,965,884,424
LINE 11	MONTH OF OCTOBER	2022	\$	34,249,586,722
LINE 12	MONTH OF NOVEMBER	2022	\$	34,547,806,515
LINE 13	MONTH OF DECEMBER	2022	\$	34,750,363,477
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		\$	31,489,703,432
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			74.6550%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		\$	105,450,752
LINE 18	JURISDICTIONAL SALES			122,096,501,415 KWH
LINE 19	TOTAL SALES			129,226,341,034 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			94.48%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		\$	99,629,870
LINE 22	INCENTIVE CAP (50 PERCENT OF PROJECTED FUEL SAVINGS AT 10 GPIF-POINT LEVEL FROM SHEET NO. 3.515)		\$	25,909,000
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)		\$	25,909,000

Note: Line 22 and 23 are as approved by Commission order PSC-13-0665-FOF-EI dated 12/18/13 effective 1/1/14.

GPIF TARGET AND RANGE SUMMARY

CONSOLIDATED FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2022

<u>Plant / Unit</u>	<u>Weighting Factor (%)</u>	<u>EAF Target (%)</u>	<u>EAF Range Max. (%)</u>	<u>Min. (%)</u>	<u>Max. Fuel Savings (\$000's)</u>	<u>Max. Fuel Loss (\$000's)</u>
Cape Canaveral 3	0.12	81.5	84.0	79.0	61	-61
Ft. Myers 2	0.09	91.7	94.2	89.2	50	-50
Manatee 3	0.29	81.4	83.9	78.9	151	-151
Martin 8	0.22	87.5	90.0	85.0	113	-113
Port Everglades 5	0.79	82.1	85.1	79.1	409	-409
Riviera 5	0.22	89.8	92.3	87.3	116	-116
Sanford 5	0.06	92.2	94.7	89.7	33	-33
St. Lucie 1	9.60	81.4	84.9	77.9	4,975	-4,975
St. Lucie 2	7.86	93.6	96.6	90.6	4,072	-4,072
Turkey Point 3	7.48	92.9	95.9	89.9	3,875	-3,875
Turkey Point 4	6.72	85.7	88.7	82.7	3,482	-3,482
Turkey Point 5	0.17	89.1	92.1	86.1	87	-87
West County 1	0.25	83.5	86.0	81.0	128	-128
West County 2	0.28	68.4	70.9	65.9	145	-145
West County 3	0.35	90.1	92.6	87.6	183	-183
	<u>34.50</u>				<u>17,880</u>	<u>-17,880</u>

GPIF TARGET AND RANGE SUMMARY

CONSOLIDATED FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2022

<u>Plant / Unit</u>	<u>Weighting Factor (%)</u>	<u>ANOHR TARGET BTU/KWH</u>	<u>NOF</u>	<u>ANOHR RANGE BTU/KWH</u>	<u>ANOHR RANGE BTU/KWH</u>	<u>Max. Fuel Savings (\$000's)</u>	<u>Max. Fuel Loss (\$000's)</u>
Cape Canaveral 3	2.55	6,726	42.6	6,648	6,804	1,321	-1,321
Ft. Myers 2	9.25	7,121	61.2	6,972	7,270	4,793	-4,793
Manatee 3	12.14	6,901	69.9	6,630	7,172	6,289	-6,289
Martin 8	3.44	6,967	70.3	6,873	7,061	1,782	-1,782
Port Everglades 5	5.06	6,597	87.1	6,509	6,685	2,622	-2,622
Riviera 5	3.67	6,633	55.5	6,547	6,719	1,900	-1,900
Sanford 5	5.47	7,275	52.2	7,112	7,438	2,837	-2,837
St. Lucie 1	0.72	10,437	98.5	10,336	10,538	372	-372
St. Lucie 2	0.57	10,297	98.4	10,202	10,392	294	-294
Turkey Point 3	0.85	10,512	98.6	10,389	10,635	441	-441
Turkey Point 4	2.02	10,900	98.5	10,612	11,188	1,045	-1,045
Turkey Point 5	4.07	7,160	59.1	7,052	7,268	2,109	-2,109
West County 1	7.42	7,220	58.8	6,948	7,492	3,848	-3,848
West County 2	3.31	7,004	60.6	6,904	7,104	1,714	-1,714
West County 3	4.96	6,997	63.0	6,880	7,114	2,571	-2,571
	<u>65.50</u>					<u>33,938</u>	<u>-33,938</u>

**GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2022**

<u>Plant/Unit</u>	<u>ANOHR</u>	<u>NOF</u>	<u>MW</u>	<u>ANOHR Equation</u>		<u>Bounds</u>	<u>First</u>	<u>Last</u>	<u>Exclusions</u>
				<u>a coef.</u>	<u>b coef.</u>				
Cape Canaveral 3	6,726	42.6	1308	6889	-3.82	78	07-18	06-21	None
Ft. Myers 2	7,121	61.2	1700	7370	-4.07	149	07-18	06-21	3/19, 4/19, 5/19, 6/19, 2/20
Manatee 3	6,901	69.9	1235	7093	-2.74	271	07-18	06-21	5/19, 7/19, 8/19, 9/19, 11/20
Martin 8	6,967	70.3	1224	7305	-4.81	94	07-18	06-21	12/18, 2/20, 12/20
Port Everglades 5	6,597	87.1	1254	7074	-5.48	88	07-18	06-21	4/21
Riviera 5	6,633	55.5	1308	6984	-6.32	86	07-18	06-21	10/18, 1/20, 2/21, 4/21
Sanford 5	7,275	52.2	1147	7616	-6.53	163	07-18	06-21	12/18, 3/19, 4/19, 5/19, 6/19, 11/20
St. Lucie 1	10,437	98.5	981	14302	-39.24	101	07-18	06-21	5/19, 6/19, 11/19
St. Lucie 2	10,297	98.4	840	13380	-31.33	95	07-18	06-21	8/18, 9/18
Turkey Point 3	10,512	98.6	837	12973	-24.96	123	07-18	06-21	7/18, 8/18, 9/18, 10/18, 4/20, 12/20
Turkey Point 4	10,900	98.5	844	16863	-60.54	288	07-18	06-21	10/20, 11/20, 3/21
Turkey Point 5	7,160	59.1	1256	7834	-11.41	108	07-18	06-21	10/19, 11/19, 12/19, 1/21, 5/21
West County 1	7,220	58.8	1223	7784	-9.60	272	07-18	06-21	11/20, 12/20
West County 2	7,004	60.6	1223	7617	-10.11	100	07-18	06-21	None
West County 3	6,997	63.0	1228	7523	-8.35	117	07-18	06-21	11/20, 12/20

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DERIVATION OF WEIGHTING FACTORS

CONSOLIDATED FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2022

PRODUCTION COSTING SIMULATION
FUEL COST (\$000)

Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Cape Canaveral 3	EAF	2,456,657	2,456,596	61	0.12
Cape Canaveral 3	ANOHR	2,456,657	2,455,336	1,321	2.55
Ft. Myers 2	EAF	2,456,657	2,456,607	50	0.09
Ft. Myers 2	ANOHR	2,456,657	2,451,864	4,793	9.25
Manatee 3	EAF	2,456,657	2,456,506	151	0.29
Manatee 3	ANOHR	2,456,657	2,450,368	6,289	12.14
Martin 8	EAF	2,456,657	2,456,544	113	0.22
Martin 8	ANOHR	2,456,657	2,454,875	1,782	3.44
Port Everglades 5	EAF	2,456,657	2,456,248	409	0.79
Port Everglades 5	ANOHR	2,456,657	2,454,035	2,622	5.06
Riviera 5	EAF	2,456,657	2,456,541	116	0.22
Riviera 5	ANOHR	2,456,657	2,454,757	1,900	3.67
Sanford 5	EAF	2,456,657	2,456,624	33	0.06
Sanford 5	ANOHR	2,456,657	2,453,820	2,837	5.47
St. Lucie 1	EAF	2,456,657	2,451,682	4,975	9.60
St. Lucie 1	ANOHR	2,456,657	2,456,285	372	0.72
St. Lucie 2	EAF	2,456,657	2,452,585	4,072	7.86
St. Lucie 2	ANOHR	2,456,657	2,456,363	294	0.57
Turkey Point 3	EAF	2,456,657	2,452,782	3,875	7.48
Turkey Point 3	ANOHR	2,456,657	2,456,216	441	0.85
Turkey Point 4	EAF	2,456,657	2,453,175	3,482	6.72
Turkey Point 4	ANOHR	2,456,657	2,455,612	1,045	2.02
Turkey Point 5	EAF	2,456,657	2,456,570	87	0.17
Turkey Point 5	ANOHR	2,456,657	2,454,548	2,109	4.07
West County 1	EAF	2,456,657	2,456,529	128	0.25
West County 1	ANOHR	2,456,657	2,452,809	3,848	7.42
West County 2	EAF	2,456,657	2,456,512	145	0.28
West County 2	ANOHR	2,456,657	2,454,943	1,714	3.31
West County 3	EAF	2,456,657	2,456,474	183	0.35
West County 3	ANOHR	2,456,657	2,454,086	2,571	4.96
TOTAL				51,818	100.00

(1) FUEL ADJUSTMENT - ALL UNITS PERFORMANCE AT TARGET

(2) ALL OTHER UNITS PERFORMANCE AT TARGET

(3) EXPRESSED IN REPLACEMENT ENERGY COSTS.

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

Cape Canaveral 3	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1 EAF (%)	91.6	76.3	41.4	61.1	66.9	91.6
2 EPOF (%)	0.0	16.7	54.8	33.3	26.9	0.0
3 EUOF (%)	8.4	7.0	3.8	5.6	6.2	8.4
4 EUOR (%)	7.8	6.6	5.3	5.3	5.8	7.8
5 PH	744	672	744	720	744	720
6 SH	744	672	504	720	744	720
7 RSH	0	0	0	0	0	0
8 UH	0	0	240	0	0	0
9 POH	0	0	240	0	0	0
10 FOH & EFOH	17	13	8	11	12	16
11 MOH & EMOH	46	35	21	30	34	44
12 Oper Mbtu	2,646,639	2,219,083	1,702,830	2,382,235	2,489,291	2,866,832
13 Net Gen (MWH)	392,968	328,948	252,533	353,133	369,112	426,866
14 ANOHR (Btu/KWH)	6,735	6,746	6,743	6,746	6,744	6,716
15 NOF (%)	40.4	37.4	38.3	37.5	37.9	45.3
16 NSC (MW)	1,308	1,308	1,308	1,308	1,308	1,308
17 ANOHR Equation	$-3.82 \times \text{NOF} + 6889$					

Cape Canaveral 3	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1 EAF (%)	91.6	91.6	91.6	91.6	91.6	91.6	81.5
2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	11.0
3 EUOF (%)	8.4	8.4	8.4	8.4	8.4	8.4	7.5
4 EUOR (%)	7.8	7.8	7.8	7.8	7.8	7.8	7.2
5 PH	744	744	720	744	720	744	8,760
6 SH	744	744	720	744	720	744	8,520
7 RSH	0	0	0	0	0	0	0
8 UH	0	0	0	0	0	0	240
9 POH	0	0	0	0	0	0	240
10 FOH & EFOH	17	17	16	17	16	17	175
11 MOH & EMOH	46	46	44	46	44	46	482
12 Oper Mbtu	3,188,396	3,180,661	3,092,973	2,926,200	2,706,152	2,521,420	31,929,775
13 Net Gen (MWH)	475,738	474,513	461,500	435,576	402,342	373,987	4,747,216
14 ANOHR (Btu/KWH)	6,702	6,703	6,702	6,718	6,726	6,742	6,726
15 NOF (%)	48.9	48.8	49.0	44.8	42.7	38.4	42.6
16 NSC (MW)	1,308	1,308	1,308	1,308	1,308	1,308	1,308
17 ANOHR Equation	$-3.82 \times \text{NOF} + 6889$						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	Ft. Myers 2	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	EAF (%)	93.2	93.2	93.2	93.2	93.2	93.2
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	6.8	6.8	6.8	6.8	6.8	6.8
4	EUOR (%)	6.4	6.4	6.4	6.4	6.4	6.4
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	14	15	15	15	15
11	MOH & EMOH	36	32	36	34	36	34
12	Oper Mbtu	5,324,727	4,878,160	5,721,063	5,463,544	5,317,711	5,311,509
13	Net Gen (MWH)	746,806	684,558	804,537	767,891	745,822	745,789
14	ANOHR (Btu/KWH)	7,130	7,126	7,111	7,115	7,130	7,122
15	NOF (%)	59.0	59.9	63.6	62.7	59.0	60.9
16	NSC (MW)	1,700	1,700	1,700	1,700	1,700	1,700
17	ANOHR Equation	-4.07 x NOF + 7370					

	Ft. Myers 2	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	EAF (%)	93.2	93.2	93.2	93.2	88.5	80.1	91.7
2	EPOF (%)	0.0	0.0	0.0	0.0	5.0	14.0	1.6
3	EUOF (%)	6.8	6.8	6.8	6.8	6.5	5.9	6.7
4	EUOR (%)	6.4	6.4	6.4	6.4	6.1	5.5	6.3
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	15	15	15	15	14	13	175
11	MOH & EMOH	36	36	34	36	33	31	412
12	Oper Mbtu	5,521,880	5,669,858	5,592,574	5,677,412	5,166,436	5,248,133	64,895,624
13	Net Gen (MWH)	775,436	797,000	786,800	798,174	724,707	735,754	9,113,274
14	ANOHR (Btu/KWH)	7,121	7,114	7,108	7,113	7,129	7,133	7,121
15	NOF (%)	61.3	63.0	64.3	63.1	59.2	58.2	61.2
16	NSC (MW)	1,700	1,700	1,700	1,700	1,700	1,700	1,700
17	ANOHR Equation	-4.07 x NOF + 7370						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	Manatee 3	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	1 EAF (%)	92.6	92.6	92.6	13.9	71.7	92.6
2	2 EPOF (%)	0.0	0.0	0.0	85.0	22.6	0.0
3	3 EUOF (%)	7.4	7.4	7.4	1.1	5.7	7.4
4	4 EUOR (%)	8.1	6.9	7.5	5.3	6.3	6.9
5	5 PH	744	672	744	720	744	720
6	6 SH	625	672	675	144	638	720
7	7 RSH	119	0	69	0	10	0
8	8 UH	0	0	0	576	96	0
9	9 POH	0	0	0	576	96	0
10	10 FOH & EFOH	17	15	17	2	13	16
11	11 MOH & EMOH	38	34	38	6	29	37
12	12 Oper Mbtu	3,284,351	3,682,300	4,019,757	841,747	3,656,574	4,395,582
13	13 Net Gen (MWH)	474,343	532,355	582,489	121,904	529,248	637,318
14	14 ANOHR (Btu/KWH)	6,924	6,917	6,901	6,905	6,909	6,897
15	15 NOF (%)	61.5	64.1	69.9	68.5	67.2	71.7
16	16 NSC (MW)	1,235	1,235	1,235	1,235	1,235	1,235
17	17 ANOHR Equation	-2.74 x NOF + 7093					

	Manatee 3	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	1 EAF (%)	92.6	92.6	92.6	60.5	90.3	92.6	81.4
2	2 EPOF (%)	0.0	0.0	0.0	34.7	2.5	0.0	12.1
3	3 EUOF (%)	7.4	7.4	7.4	4.8	7.2	7.4	6.5
4	4 EUOR (%)	6.9	6.9	6.9	4.6	7.0	6.9	6.8
5	5 PH	744	744	720	744	720	744	8,760
6	6 SH	744	744	720	744	686	742	7,854
7	7 RSH	0	0	0	0	34	2	234
8	8 UH	0	0	0	0	0	0	672
9	9 POH	0	0	0	0	0	0	672
10	10 FOH & EFOH	17	17	16	11	16	17	175
11	11 MOH & EMOH	38	38	37	25	36	38	394
12	12 Oper Mbtu	4,797,358	4,891,331	4,899,576	3,777,229	4,274,549	4,287,077	46,816,046
13	13 Net Gen (MWH)	696,784	710,846	712,873	544,976	620,219	620,596	6,783,951
14	14 ANOHR (Btu/KWH)	6,885	6,881	6,873	6,931	6,892	6,908	6,901
15	15 NOF (%)	75.8	77.4	80.2	59.3	73.2	67.7	69.9
16	16 NSC (MW)	1,235	1,235	1,235	1,235	1,235	1,235	1,235
17	17 ANOHR Equation	-2.74 x NOF + 7093						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	Martin 8	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	1 EAF (%)	93.3	93.3	81.3	74.6	93.3	75.4
2	2 EPOF (%)	0.0	0.0	12.9	20.0	0.0	19.2
3	3 EUOF (%)	6.7	6.7	5.8	5.4	6.7	5.4
4	4 EUOR (%)	63.3	17.3	6.3	6.4	6.3	6.2
5	5 PH	744	672	744	720	744	720
6	6 SH	29	215	646	568	738	588
7	7 RSH	715	457	2	8	6	132
8	8 UH	0	0	96	144	0	0
9	9 POH	0	0	96	144	0	0
10	10 FOH & EFOH	16	14	14	12	16	12
11	11 MOH & EMOH	34	31	30	26	34	27
12	12 Oper Mbtu	250,679	1,298,347	4,225,226	3,550,140	4,439,749	3,275,284
13	13 Net Gen (MWH)	36,832	186,437	609,349	510,738	637,437	468,433
14	14 ANOHR (Btu/KWH)	6,806	6,964	6,934	6,951	6,965	6,992
15	15 NOF (%)	103.8	70.8	77.1	73.5	70.6	65.1
16	16 NSC (MW)	1,224	1,224	1,224	1,224	1,224	1,224
17	17 ANOHR Equation	-4.81 x NOF + 7305					

	Martin 8	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	1 EAF (%)	93.3	93.3	93.3	93.3	80.9	85.0	87.5
2	2 EPOF (%)	0.0	0.0	0.0	0.0	13.3	8.9	6.2
3	3 EUOF (%)	6.7	6.7	6.7	6.7	5.8	6.1	6.3
4	4 EUOR (%)	6.3	6.3	6.3	6.3	7.0	9.8	7.6
5	5 PH	744	744	720	744	720	744	8,760
6	6 SH	744	744	720	744	559	419	6,714
7	7 RSH	0	0	0	0	161	325	1806
8	8 UH	0	0	0	0	0	0	240
9	9 POH	0	0	0	0	0	0	240
10	10 FOH & EFOH	16	16	15	16	13	14	175
11	11 MOH & EMOH	34	34	33	34	29	31	377
12	12 Oper Mbtu	4,524,666	4,493,618	4,401,810	4,618,450	2,992,977	2,171,555	40,254,295
13	13 Net Gen (MWH)	649,909	645,264	632,444	664,143	427,263	309,603	5,777,852
14	14 ANOHR (Btu/KWH)	6,962	6,964	6,960	6,954	7,005	7,014	6,967
15	15 NOF (%)	71.4	70.9	71.8	72.9	62.4	60.4	70.3
16	16 NSC (MW)	1,224	1,224	1,224	1,224	1,224	1,224	1,224
17	17 ANOHR Equation	-4.81 x NOF + 7305						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

Port Everglades 5	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1 EAF (%)	90.8	90.8	90.8	90.8	90.8	90.8
2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3 EUOF (%)	9.2	9.2	9.2	9.2	9.2	9.2
4 EUOR (%)	8.4	8.4	8.4	8.4	8.4	8.4
5 PH	744	672	744	720	744	720
6 SH	744	672	744	720	744	720
7 RSH	0	0	0	0	0	0
8 UH	0	0	0	0	0	0
9 POH	0	0	0	0	0	0
10 FOH & EFOH	16	15	16	16	16	16
11 MOH & EMOH	52	47	52	50	52	50
12 Oper Mbtu	5,637,940	4,935,679	5,545,169	5,217,443	5,049,860	5,277,047
13 Net Gen (MWH)	858,134	749,306	842,859	791,241	762,128	801,009
14 ANOHR (Btu/KWH)	6,570	6,587	6,579	6,594	6,626	6,588
15 NOF (%)	92.0	88.9	90.3	87.6	81.7	88.7
16 NSC (MW)	1,254	1,254	1,254	1,254	1,254	1,254
17 ANOHR Equation	$-5.48 \times \text{NOF} + 7074$					

Port Everglades 5	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1 EAF (%)	90.8	90.8	90.8	26.3	51.5	90.8	82.1
2 EPOF (%)	0.0	0.0	0.0	71.0	43.3	0.0	9.6
3 EUOF (%)	9.2	9.2	9.2	2.7	5.2	9.2	8.3
4 EUOR (%)	8.4	8.4	8.4	8.4	8.4	8.4	8.4
5 PH	744	744	720	744	720	744	8,760
6 SH	744	744	720	216	408	744	7,920
7 RSH	0	0	0	0	0	0	0
8 UH	0	0	0	528	312	0	840
9 POH	0	0	0	528	312	0	840
10 FOH & EFOH	16	16	16	5	9	16	175
11 MOH & EMOH	52	52	50	15	28	52	552
12 Oper Mbtu	5,502,631	5,521,498	5,327,089	1,620,514	3,083,987	4,347,746	57,091,639
13 Net Gen (MWH)	835,885	839,006	809,219	246,466	469,333	649,596	8,654,182
14 ANOHR (Btu/KWH)	6,583	6,581	6,583	6,575	6,571	6,693	6,597
15 NOF (%)	89.6	89.9	89.6	91.0	91.7	69.6	87.1
16 NSC (MW)	1,254	1,254	1,254	1,254	1,254	1,254	1,254
17 ANOHR Equation	$-5.48 \times \text{NOF} + 7074$						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	Riviera 5	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	EAFF (%)	92.3	92.3	62.5	92.3	92.3	92.3
2	EPOF (%)	0.0	0.0	32.3	0.0	0.0	0.0
3	EUOF (%)	7.7	7.7	5.2	7.7	7.7	7.7
4	EUOR (%)	7.2	7.2	7.2	7.2	7.2	7.2
5	PH	744	672	744	720	744	720
6	SH	744	672	504	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	240	0	0	0
9	POH	0	0	240	0	0	0
10	FOH & EFOH	15	14	10	15	15	15
11	MOH & EMOH	42	38	29	41	42	41
12	Oper Mbtu	3,312,549	2,986,421	2,583,762	3,602,834	3,772,467	3,472,170
13	Net Gen (MWH)	497,305	448,277	390,946	544,317	570,376	523,469
14	ANOHR (Btu/KWH)	6,661	6,662	6,609	6,619	6,614	6,633
15	NOF (%)	51.1	51.0	59.3	57.8	58.6	55.6
16	NSC (MW)	1,308	1,308	1,308	1,308	1,308	1,308
17	ANOHR Equation	-6.32 x NOF + 6984					

	Riviera 5	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	EAFF (%)	92.3	92.3	92.3	92.3	92.3	92.3	89.8
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.7
3	EUOF (%)	7.7	7.7	7.7	7.7	7.7	7.7	7.5
4	EUOR (%)	7.2	7.2	7.2	7.2	7.2	7.2	7.2
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,520
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	240
9	POH	0	0	0	0	0	0	240
10	FOH & EFOH	15	15	15	15	15	15	175
11	MOH & EMOH	42	42	41	42	41	42	482
12	Oper Mbtu	3,956,664	3,900,521	3,831,193	3,489,820	3,154,178	2,920,731	40,998,812
13	Net Gen (MWH)	600,040	590,988	581,012	525,338	473,103	435,865	6,181,036
14	ANOHR (Btu/KWH)	6,594	6,600	6,594	6,643	6,667	6,701	6,633
15	NOF (%)	61.7	60.7	61.7	54.0	50.2	44.8	55.5
16	NSC (MW)	1,308	1,308	1,308	1,308	1,308	1,308	1,308
17	ANOHR Equation	-6.32 x NOF + 6984						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	Sanford 5	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	1 EAF (%)	94.8	60.9	94.8	94.8	94.8	94.8
2	2 EPOF (%)	0.0	35.7	0.0	0.0	0.0	0.0
3	3 EUOF (%)	5.2	3.4	5.2	5.2	5.2	5.2
4	4 EUOR (%)	5.0	5.0	5.0	5.0	5.0	5.0
5	5 PH	744	672	744	720	744	720
6	6 SH	744	432	744	720	744	720
7	7 RSH	0	0	0	0	0	0
8	8 UH	0	240	0	0	0	0
9	9 POH	0	240	0	0	0	0
10	10 FOH & EFOH	15	9	15	15	15	15
11	11 MOH & EMOH	24	14	24	23	24	23
12	12 Oper Mbtu	2,904,655	1,733,601	3,258,828	3,267,080	3,088,089	3,155,435
13	13 Net Gen (MWH)	397,245	237,382	448,072	450,011	423,490	433,856
14	14 ANOHR (Btu/KWH)	7,312	7,303	7,273	7,260	7,292	7,273
15	15 NOF (%)	46.6	47.9	52.5	54.5	49.6	52.5
16	16 NSC (MW)	1,147	1,147	1,147	1,147	1,147	1,147
17	17 ANOHR Equation	-6.53 x NOF + 7616					

	Sanford 5	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	1 EAF (%)	94.8	94.8	94.8	94.8	94.8	94.8	92.2
2	2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.7
3	3 EUOF (%)	5.2	5.2	5.2	5.2	5.2	5.2	5.1
4	4 EUOR (%)	5.0	5.0	5.0	5.0	5.0	5.0	5.0
5	5 PH	744	744	720	744	720	744	8,760
6	6 SH	744	744	720	744	720	744	8,520
7	7 RSH	0	0	0	0	0	0	0
8	8 UH	0	0	0	0	0	0	240
9	9 POH	0	0	0	0	0	0	240
10	10 FOH & EFOH	15	15	15	15	15	15	175
11	11 MOH & EMOH	24	24	23	24	23	24	272
12	12 Oper Mbtu	3,333,967	3,526,523	3,523,941	3,409,143	2,906,528	3,017,455	37,134,597
13	13 Net Gen (MWH)	458,908	486,887	487,338	469,773	398,100	413,350	5,104,412
14	14 ANOHR (Btu/KWH)	7,265	7,243	7,231	7,257	7,301	7,300	7,275
15	15 NOF (%)	53.8	57.1	59.0	55.0	48.2	48.4	52.2
16	16 NSC (MW)	1,147	1,147	1,147	1,147	1,147	1,147	1,147
17	17 ANOHR Equation	-6.53 x NOF + 7616						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

St. Lucie 1	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1 EAF (%)	88.7	88.7	88.7	88.7	88.7	88.7
2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3 EUOF (%)	11.3	11.3	11.3	11.3	11.3	11.3
4 EUOR (%)	10.2	10.2	10.2	10.2	10.2	10.2
5 PH	744	672	744	720	744	720
6 SH	744	672	744	720	744	720
7 RSH	0	0	0	0	0	0
8 UH	0	0	0	0	0	0
9 POH	0	0	0	0	0	0
10 FOH & EFOH	58	53	58	56	58	56
11 MOH & EMOH	26	23	26	25	26	25
12 Oper Mbtu	7,559,674	6,828,095	7,559,674	7,214,102	7,454,574	7,214,102
13 Net Gen (MWH)	727,591	657,179	727,591	688,631	711,586	688,631
14 ANOHR (Btu/KWH)	10,390	10,390	10,390	10,476	10,476	10,476
15 NOF (%)	99.7	99.7	99.7	97.5	97.5	97.5
16 NSC (MW)	981	981	981	981	981	981
17 ANOHR Equation	-39.24 x NOF + 14302					

St. Lucie 1	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1 EAF (%)	88.7	88.7	5.9	82.9	88.7	88.7	81.4
2 EPOF (%)	0.0	0.0	93.3	6.5	0.0	0.0	8.2
3 EUOF (%)	11.3	11.3	0.8	10.6	11.3	11.3	10.4
4 EUOR (%)	10.2	10.2	10.2	10.2	10.2	10.2	10.2
5 PH	744	744	720	744	720	744	8,760
6 SH	744	744	48	696	720	744	8,040
7 RSH	0	0	0	0	0	0	0
8 UH	0	0	672	48	0	0	720
9 POH	0	0	672	48	0	0	720
10 FOH & EFOH	58	58	4	55	56	58	631
11 MOH & EMOH	26	26	2	24	25	26	280
12 Oper Mbtu	7,454,574	7,454,574	480,945	6,973,630	7,315,818	7,559,674	81,071,287
13 Net Gen (MWH)	711,586	711,586	45,909	665,677	704,121	727,591	7,767,681
14 ANOHR (Btu/KWH)	10,476	10,476	10,476	10,476	10,390	10,390	10,437
15 NOF (%)	97.5	97.5	97.5	97.5	99.7	99.7	98.5
16 NSC (MW)	981	981	981	981	981	981	981
17 ANOHR Equation	-39.24 x NOF + 14302						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

St. Lucie 2	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1 EAF (%)	93.6	93.6	93.6	93.6	93.6	93.6
2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3 EUOF (%)	6.4	6.4	6.4	6.4	6.4	6.4
4 EUOR (%)	6.0	6.0	6.0	6.0	6.0	6.0
5 PH	744	672	744	720	744	720
6 SH	744	672	744	720	744	720
7 RSH	0	0	0	0	0	0
8 UH	0	0	0	0	0	0
9 POH	0	0	0	0	0	0
10 FOH & EFOH	24	22	24	23	24	23
11 MOH & EMOH	24	22	24	23	24	23
12 Oper Mbtu	6,392,871	5,774,206	6,392,871	6,088,004	6,290,939	6,088,004
13 Net Gen (MWH)	623,512	563,172	623,512	589,637	609,292	589,637
14 ANOHR (Btu/KWH)	10,253	10,253	10,253	10,325	10,325	10,325
15 NOF (%)	99.8	99.8	99.8	97.5	97.5	97.5
16 NSC (MW)	840	840	840	840	840	840
17 ANOHR Equation	-31.33 x NOF + 13380					

St. Lucie 2	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1 EAF (%)	93.6	93.6	93.6	93.6	93.6	93.6	93.6
2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 EUOF (%)	6.4	6.4	6.4	6.4	6.4	6.4	6.4
4 EUOR (%)	6.0	6.0	6.0	6.0	6.0	6.0	6.0
5 PH	744	744	720	744	720	744	8,760
6 SH	744	744	720	744	720	744	8,760
7 RSH	0	0	0	0	0	0	0
8 UH	0	0	0	0	0	0	0
9 POH	0	0	0	0	0	0	0
10 FOH & EFOH	24	24	23	24	23	24	280
11 MOH & EMOH	24	24	23	24	23	24	280
12 Oper Mbtu	6,290,939	6,290,939	6,088,004	6,290,939	6,186,649	6,392,871	74,583,099
13 Net Gen (MWH)	609,292	609,292	589,637	609,292	603,399	623,512	7,243,187
14 ANOHR (Btu/KWH)	10,325	10,325	10,325	10,325	10,253	10,253	10,297
15 NOF (%)	97.5	97.5	97.5	97.5	99.8	99.8	98.4
16 NSC (MW)	840	840	840	840	840	840	840
17 ANOHR Equation	-31.33 x NOF + 13380						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	Turkey Point 3	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	EAFF (%)	92.9	92.9	92.9	92.9	92.9	92.9
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	7.1	7.1	7.1	7.1	7.1	7.1
4	EUOR (%)	6.6	6.6	6.6	6.6	6.6	6.6
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	29	26	29	28	29	28
11	MOH & EMOH	24	22	24	23	24	23
12	Oper Mbtu	6,526,973	5,895,330	6,526,973	6,192,632	6,399,049	6,192,632
13	Net Gen (MWH)	623,100	562,800	623,100	587,592	607,178	587,592
14	ANOHR (Btu/KWH)	10,475	10,475	10,475	10,539	10,539	10,539
15	NOF (%)	100.1	100.1	100.1	97.5	97.5	97.5
16	NSC (MW)	837	837	837	837	837	837
17	ANOHR Equation	-24.96 x NOF + 12973					

	Turkey Point 3	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	EAFF (%)	92.9	92.9	92.9	92.9	92.9	92.9	92.9
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	7.1	7.1	7.1	7.1	7.1	7.1	7.1
4	EUOR (%)	6.6	6.6	6.6	6.6	6.6	6.6	6.6
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	29	29	28	29	28	29	342
11	MOH & EMOH	24	24	23	24	23	24	280
12	Oper Mbtu	6,399,049	6,399,049	6,192,632	6,399,049	6,316,425	6,526,973	75,965,893
13	Net Gen (MWH)	607,178	607,178	587,592	607,178	603,000	623,100	7,226,588
14	ANOHR (Btu/KWH)	10,539	10,539	10,539	10,539	10,475	10,475	10,512
15	NOF (%)	97.5	97.5	97.5	97.5	100.1	100.1	98.6
16	NSC (MW)	837	837	837	837	837	837	837
17	ANOHR Equation	-24.96 x NOF + 12973						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	Turkey Point 4	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	EAF (%)	93.0	93.0	33.0	65.1	93.0	93.0
2	EPOF (%)	0.0	0.0	64.5	30.0	0.0	0.0
3	EUOF (%)	7.0	7.0	2.5	4.9	7.0	7.0
4	EUOR (%)	6.5	6.5	6.5	6.5	6.5	6.5
5	PH	744	672	744	720	744	720
6	SH	744	672	264	504	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	480	216	0	0
9	POH	0	0	480	216	0	0
10	FOH & EFOH	26	23	9	18	26	25
11	MOH & EMOH	26	23	9	18	26	25
12	Oper Mbtu	6,790,581	6,133,427	2,409,564	4,545,572	6,710,128	6,493,668
13	Net Gen (MWH)	628,234	567,437	222,922	414,742	612,238	592,488
14	ANOHR (Btu/KWH)	10,809	10,809	10,809	10,960	10,960	10,960
15	NOF (%)	100.0	100.0	100.0	97.5	97.5	97.5
16	NSC (MW)	844	844	844	844	844	844
17	ANOHR Equation	-60.54 x NOF + 16863					

	Turkey Point 4	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	EAF (%)	93.0	93.0	93.0	93.0	93.0	93.0	85.7
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	7.9
3	EUOF (%)	7.0	7.0	7.0	7.0	7.0	7.0	6.4
4	EUOR (%)	6.5	6.5	6.5	6.5	6.5	6.5	6.5
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,064
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	696
9	POH	0	0	0	0	0	0	696
10	FOH & EFOH	26	26	25	26	25	26	280
11	MOH & EMOH	26	26	25	26	25	26	280
12	Oper Mbtu	6,710,128	6,710,128	6,493,668	6,710,128	6,571,526	6,790,581	73,067,769
13	Net Gen (MWH)	612,238	612,238	592,488	612,238	607,968	628,234	6,703,465
14	ANOHR (Btu/KWH)	10,960	10,960	10,960	10,960	10,809	10,809	10,900
15	NOF (%)	97.5	97.5	97.5	97.5	100.0	100.0	98.5
16	NSC (MW)	844	844	844	844	844	844	844
17	ANOHR Equation	-60.54 x NOF + 16863						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	Turkey Point 5	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	1 EAF (%)	90.8	90.8	90.8	90.8	90.8	90.8
2	2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	3 EUOF (%)	9.2	9.2	9.2	9.2	9.2	9.2
4	4 EUOR (%)	8.4	8.4	8.4	10.6	11.9	8.4
5	5 PH	744	672	744	720	744	720
6	6 SH	744	672	744	555	507	720
7	7 RSH	0	0	0	165	237	0
8	8 UH	0	0	0	0	0	0
9	9 POH	0	0	0	0	0	0
10	10 FOH & EFOH	15	14	15	15	15	15
11	11 MOH & EMOH	53	48	53	51	53	51
12	12 Oper Mbtu	3,450,361	3,320,174	4,210,622	3,047,894	2,542,040	3,929,720
13	13 Net Gen (MWH)	475,715	460,368	592,128	427,175	352,963	550,458
14	14 ANOHR (Btu/KWH)	7,253	7,212	7,111	7,135	7,202	7,139
15	15 NOF (%)	50.9	54.5	63.4	61.3	55.4	60.9
16	16 NSC (MW)	1,256	1,256	1,256	1,256	1,256	1,256
17	17 ANOHR Equation	-11.41 x NOF + 7834					

	Turkey Point 5	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	1 EAF (%)	90.8	90.8	90.8	90.8	90.8	70.3	89.1
2	2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	22.6	1.9
3	3 EUOF (%)	9.2	9.2	9.2	9.2	9.2	7.1	9
4	4 EUOR (%)	8.4	8.4	8.4	9.7	16.9	8.4	9.3
5	5 PH	744	744	720	744	720	744	8,760
6	6 SH	744	744	720	635	324	576	7,685
7	7 RSH	0	0	0	109	396	0	907
8	8 UH	0	0	0	0	0	168	168
9	9 POH	0	0	0	0	0	168	168
10	10 FOH & EFOH	15	15	15	15	15	12	175
11	11 MOH & EMOH	53	53	51	53	51	41	613
12	12 Oper Mbtu	4,073,336	4,036,867	3,928,956	3,760,424	1,905,476	2,580,843	40,815,122
13	13 Net Gen (MWH)	570,735	565,071	550,274	531,659	269,135	354,755	5,700,436
14	14 ANOHR (Btu/KWH)	7,137	7,144	7,140	7,073	7,080	7,275	7,160
15	15 NOF (%)	61.1	60.5	60.8	66.7	66.1	49.0	59.1
16	16 NSC (MW)	1,256	1,256	1,256	1,256	1,256	1,256	1,256
17	17 ANOHR Equation	-11.41 x NOF + 7834						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	West County 1	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	1 EAF (%)	91.9	91.9	91.9	91.9	91.9	91.9
2	2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	3 EUOF (%)	8.1	8.1	8.1	8.1	8.1	8.1
4	4 EUOR (%)	24.3	10.6	8.1	7.5	9.0	9.2
5	5 PH	744	672	744	720	744	720
6	6 SH	189	463	686	720	614	576
7	7 RSH	555	209	58	0	130	144
8	8 UH	0	0	0	0	0	0
9	9 POH	0	0	0	0	0	0
10	10 FOH & EFOH	16	15	16	16	16	16
11	11 MOH & EMOH	44	40	44	43	44	43
12	12 Oper Mbtu	1,169,065	2,391,262	3,608,604	4,193,828	3,449,178	3,168,938
13	13 Net Gen (MWH)	164,657	331,108	500,361	587,042	481,124	441,172
14	14 ANOHR (Btu/KWH)	7,100	7,222	7,212	7,144	7,169	7,183
15	15 NOF (%)	71.2	58.5	59.6	66.7	64.1	62.6
16	16 NSC (MW)	1,223	1,223	1,223	1,223	1,223	1,223
17	17 ANOHR Equation	-9.6 x NOF + 7784					

	West County 1	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	1 EAF (%)	91.9	91.9	75.5	61.3	61.3	69.2	83.5
2	2 EPOF (%)	0.0	0.0	17.8	33.3	33.3	24.7	9.1
3	3 EUOF (%)	8.1	8.1	6.7	5.4	5.4	6.1	7.4
4	4 EUOR (%)	8.6	9.8	7.0	5.8	20.0	18.4	9.6
5	5 PH	744	744	720	744	720	744	8,760
6	6 SH	646	556	636	657	156	202	6,101
7	7 RSH	98	188	84	87	564	542	2659
8	8 UH	0	0	0	0	0	0	0
9	9 POH	0	0	0	0	0	0	0
10	10 FOH & EFOH	16	16	13	11	11	12	175
11	11 MOH & EMOH	44	44	35	29	29	33	473
12	12 Oper Mbtu	3,519,066	3,098,078	3,063,556	2,594,913	645,134	742,723	31,690,501
13	13 Net Gen (MWH)	489,439	431,848	421,745	352,426	87,881	100,463	4,389,266
14	14 ANOHR (Btu/KWH)	7,190	7,174	7,264	7,363	7,341	7,393	7,220
15	15 NOF (%)	61.9	63.5	54.2	43.9	46.1	40.7	58.8
16	16 NSC (MW)	1,223	1,223	1,223	1,223	1,223	1,223	1,223
17	17 ANOHR Equation	-9.6 x NOF + 7784						

ESTIMATED UNIT PERFORMANCE DATA

CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

	West County 2	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1	EAF (%)	92.4	46.2	0.0	10.3	61.7	61.7
2	EPOF (%)	0.0	50.0	100.0	88.9	33.3	33.3
3	EUOF (%)	7.6	3.8	0.0	0.8	5.0	5.0
4	EUOR (%)	7.0	7.0	0.0	4.8	4.8	4.8
5	PH	744	672	744	720	744	720
6	SH	744	336	0	120	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	336	744	600	0	0
9	POH	0	336	744	600	0	0
10	FOH & EFOH	20	9	0	2	13	13
11	MOH & EMOH	36	16	0	4	24	23
12	Oper Mbtu	3,490,786	1,569,472	0	492,548	3,005,853	2,750,377
13	Net Gen (MWH)	493,886	221,959	0	68,965	420,399	383,221
14	ANOHR (Btu/KWH)	7,068	7,071	0	7,142	7,150	7,177
15	NOF (%)	54.3	54.0	0.0	47.0	46.2	43.5
16	NSC (MW)	1,223	1,223	1,223	1,223	1,223	1,223
17	ANOHR Equation	-10.11 x NOF + 7617					

	West County 2	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1	EAF (%)	83.5	92.4	92.4	92.4	92.4	92.4	68.4
2	EPOF (%)	9.7	0.0	0.0	0.0	0.0	0.0	26.0
3	EUOF (%)	6.8	7.6	7.6	7.6	7.6	7.6	5.6
4	EUOR (%)	6.4	7.0	7.0	7.0	7.0	7.0	6.5
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	7,080
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	1,680
9	POH	0	0	0	0	0	0	1,680
10	FOH & EFOH	18	20	19	20	19	20	175
11	MOH & EMOH	33	36	35	36	35	36	315
12	Oper Mbtu	3,982,545	4,678,764	4,572,899	4,625,475	3,881,422	3,596,003	36,756,880
13	Net Gen (MWH)	570,320	682,135	667,479	673,384	556,237	509,999	5,247,984
14	ANOHR (Btu/KWH)	6,983	6,859	6,851	6,869	6,978	7,051	7,004
15	NOF (%)	62.7	75.0	75.8	74.0	63.2	56.0	60.6
16	NSC (MW)	1,223	1,223	1,223	1,223	1,223	1,223	1,223
17	ANOHR Equation	-10.11 x NOF + 7617						

ESTIMATED UNIT PERFORMANCE DATA

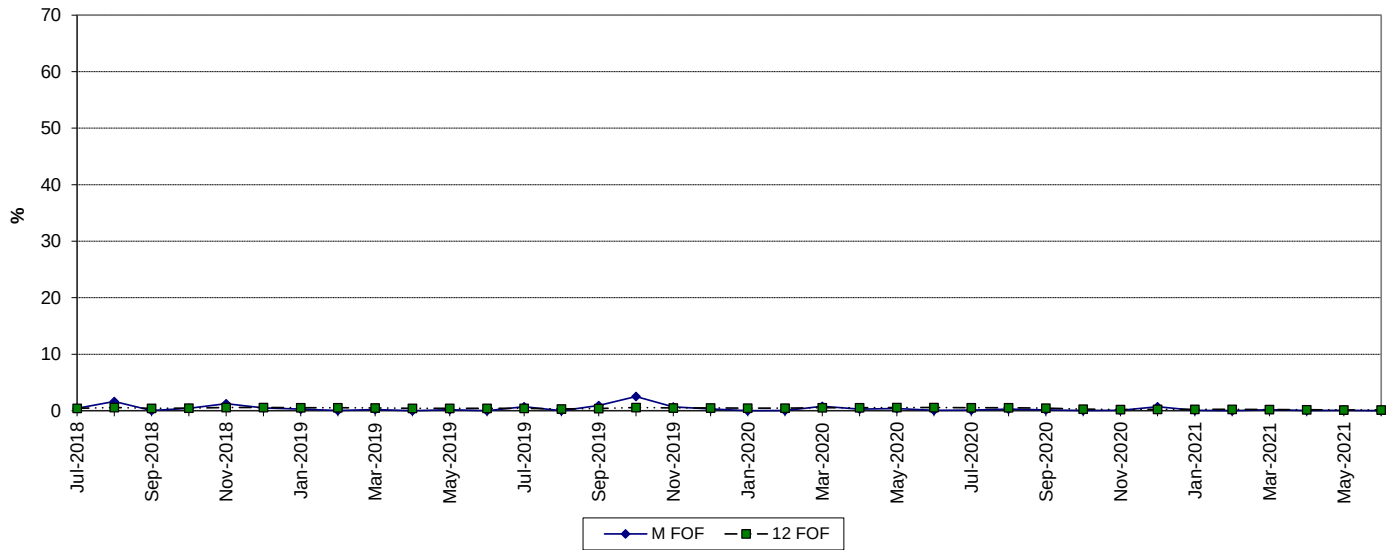
CONSOLIDATED FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

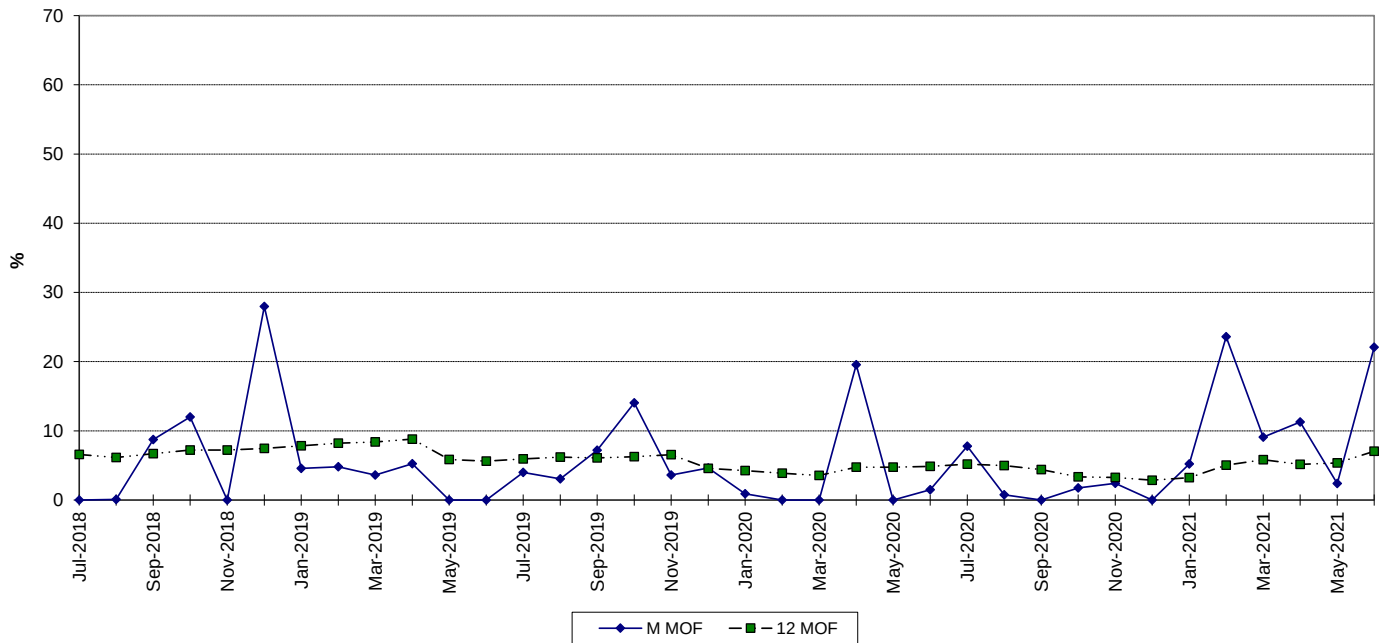
West County 3	Jan '22	Feb '22	Mar '22	Apr '22	May '22	Jun '22
1 EAF (%)	92.6	92.6	92.6	92.6	92.6	92.6
2 EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3 EUOF (%)	7.4	7.4	7.4	7.4	7.4	7.4
4 EUOR (%)	6.9	6.9	6.9	6.9	6.9	6.9
5 PH	744	672	744	720	744	720
6 SH	744	672	744	720	744	720
7 RSH	0	0	0	0	0	0
8 UH	0	0	0	0	0	0
9 POH	0	0	0	0	0	0
10 FOH & EFOH	15	14	15	15	15	15
11 MOH & EMOH	40	36	40	38	40	38
12 Oper Mbtu	3,967,016	3,543,788	4,075,554	4,464,008	4,325,764	3,992,118
13 Net Gen (MWH)	566,312	505,389	583,055	645,741	622,054	571,691
14 ANOHR (Btu/KWH)	7,005	7,012	6,990	6,913	6,954	6,983
15 NOF (%)	62.0	61.2	63.8	73.0	68.1	64.7
16 NSC (MW)	1,228	1,228	1,228	1,228	1,228	1,228
17 ANOHR Equation	$-8.35 \times \text{NOF} + 7523$					

West County 3	Jul '22	Aug '22	Sep '22	Oct '22	Nov '22	Dec '22	Total
1 EAF (%)	92.6	92.6	92.6	92.6	80.3	74.6	90.1
2 EPOF (%)	0.0	0.0	0.0	0.0	13.3	19.4	2.7
3 EUOF (%)	7.4	7.4	7.4	7.4	6.4	6.0	7.2
4 EUOR (%)	6.9	6.9	6.9	6.9	6.9	6.9	6.9
5 PH	744	744	720	744	720	744	8,760
6 SH	744	744	720	744	624	600	8,520
7 RSH	0	0	0	0	0	0	0
8 UH	0	0	0	0	96	144	240
9 POH	0	0	0	0	96	144	240
10 FOH & EFOH	15	15	15	15	13	12	175
11 MOH & EMOH	40	40	38	40	33	32	456
12 Oper Mbtu	4,211,132	3,950,683	3,905,875	3,998,999	3,129,061	2,533,090	46,123,958
13 Net Gen (MWH)	604,093	563,739	558,381	571,204	444,532	355,771	6,591,962
14 ANOHR (Btu/KWH)	6,971	7,008	6,995	7,001	7,039	7,120	6,997
15 NOF (%)	66.1	61.7	63.2	62.5	58.0	48.3	63.0
16 NSC (MW)	1,228	1,228	1,228	1,228	1,228	1,228	1,228
17 ANOHR Equation	$-8.35 \times \text{NOF} + 7523$						

CAPE CANAVERAL 3 FORCED OUTAGE FACTOR

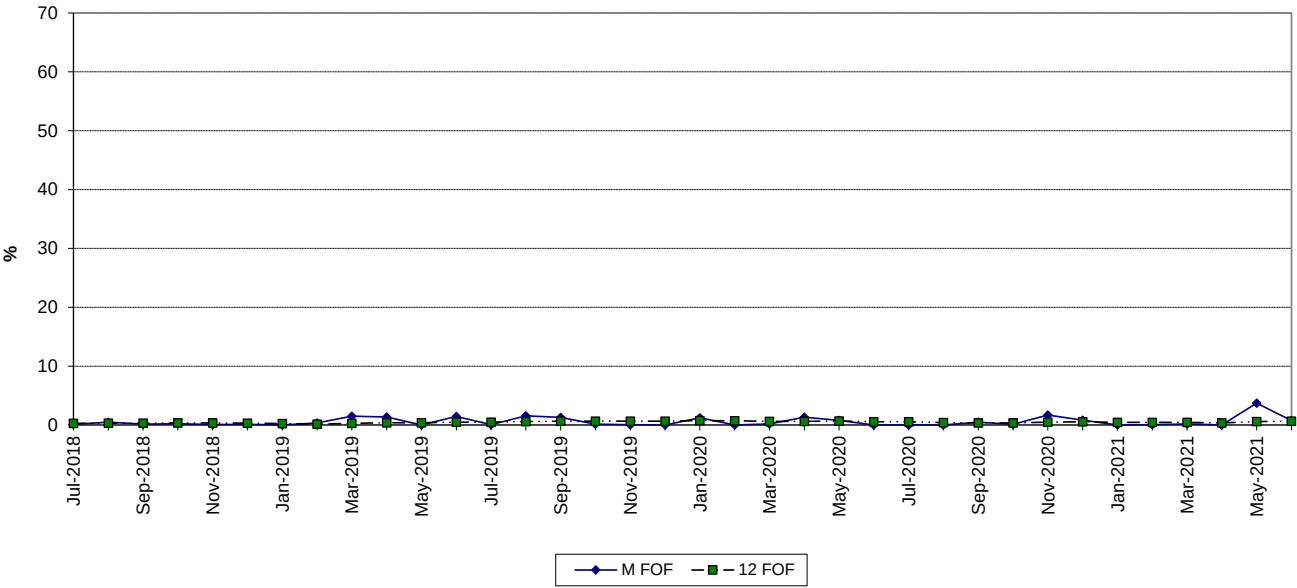


MAINTENANCE OUTAGE FACTOR

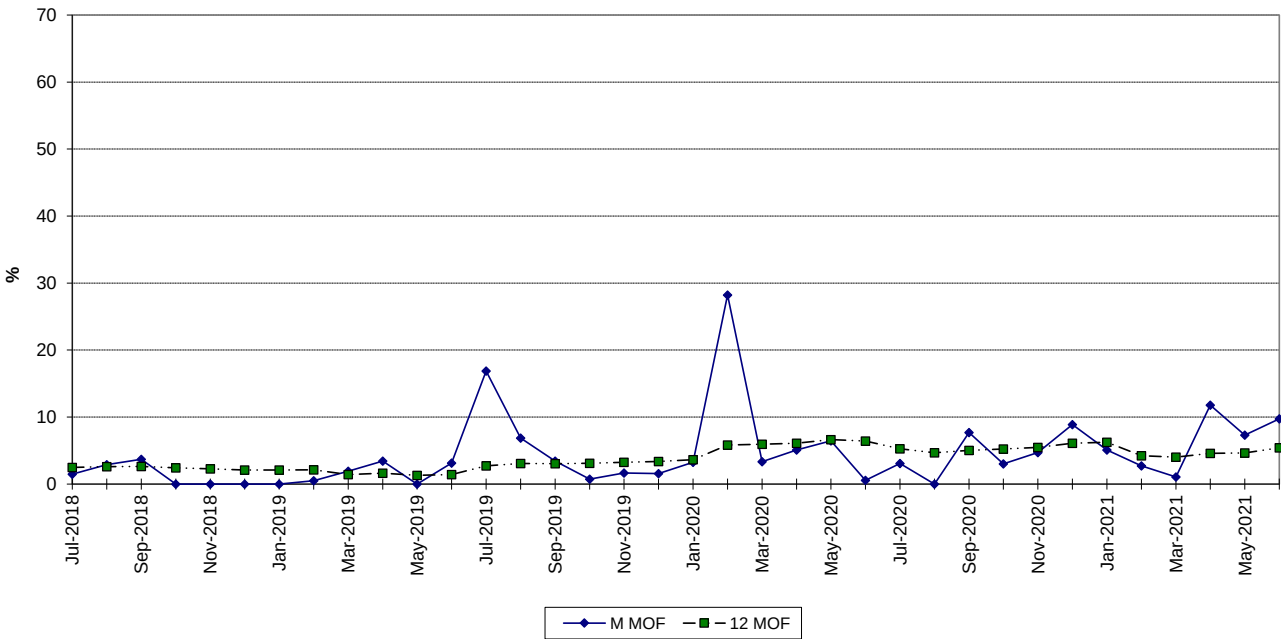


FT. MYERS 2

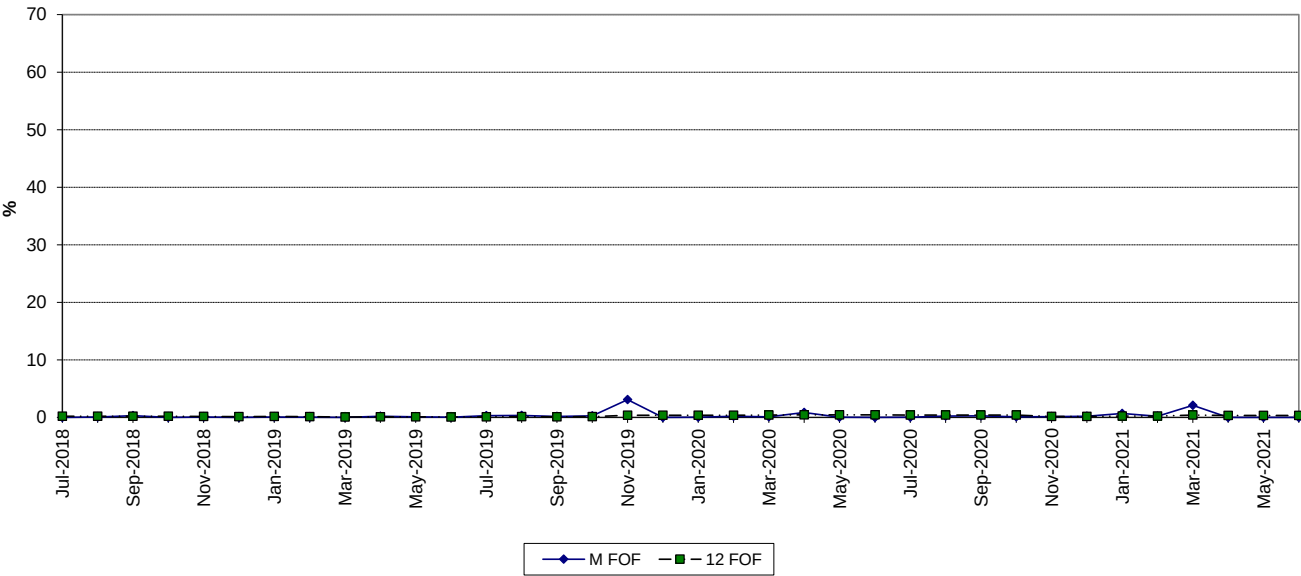
FORCED OUTAGE FACTOR



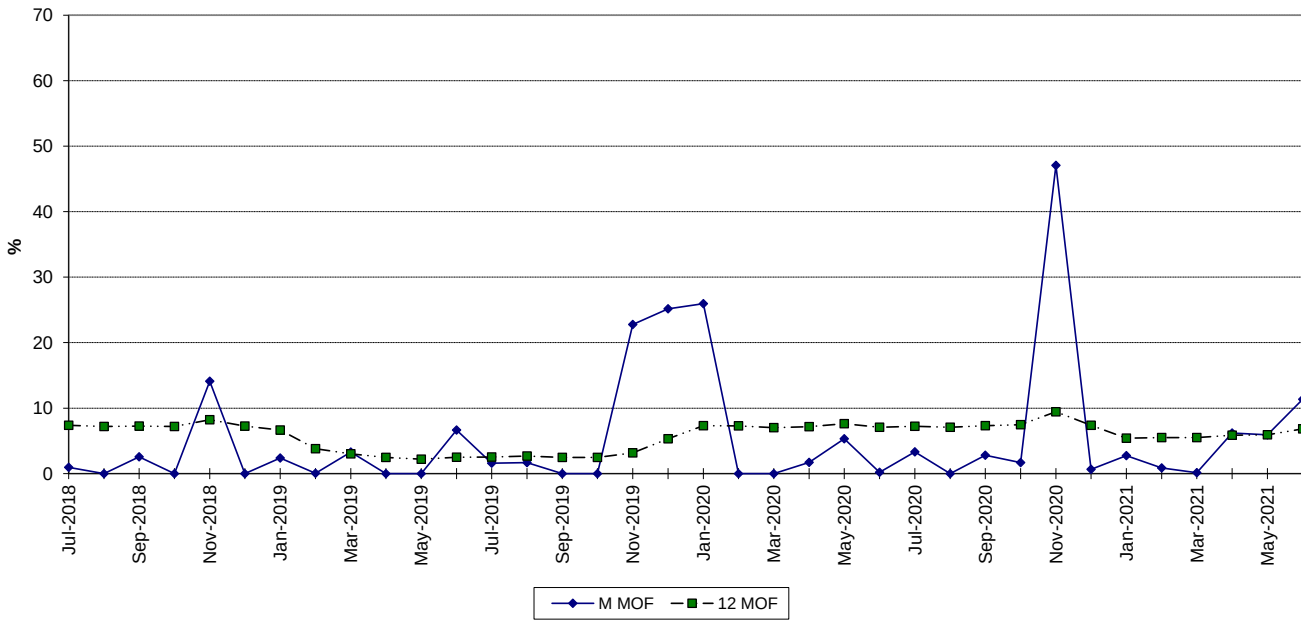
MAINTENANCE OUTAGE FACTOR



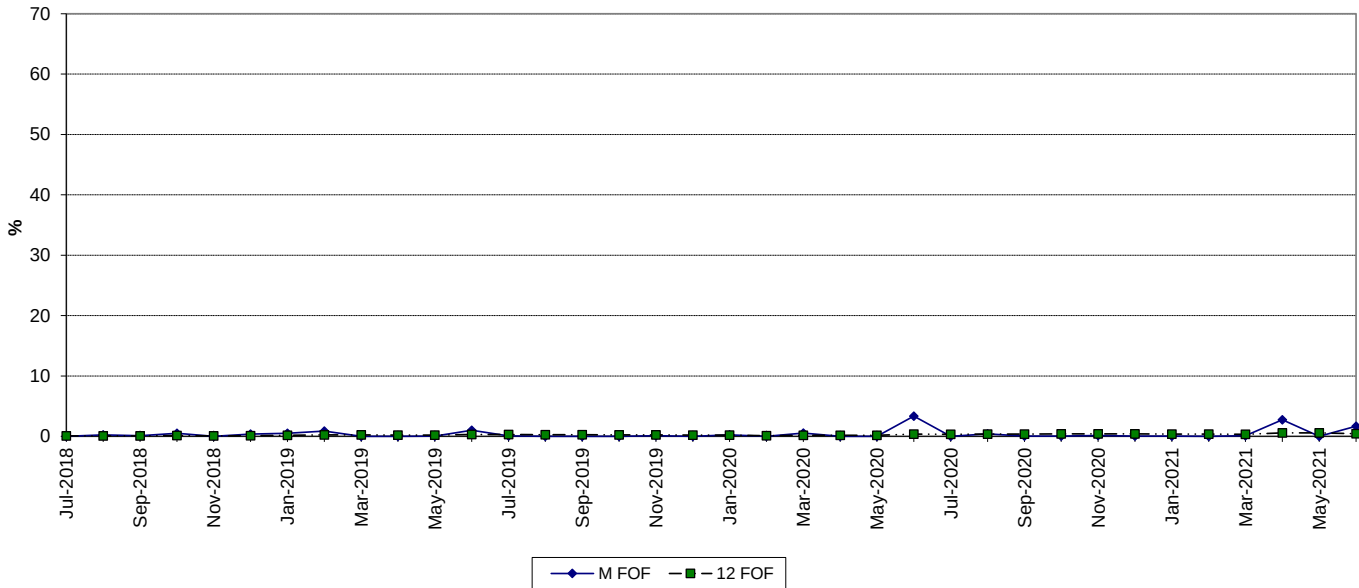
MANATEE 3
FORCED OUTAGE FACTOR



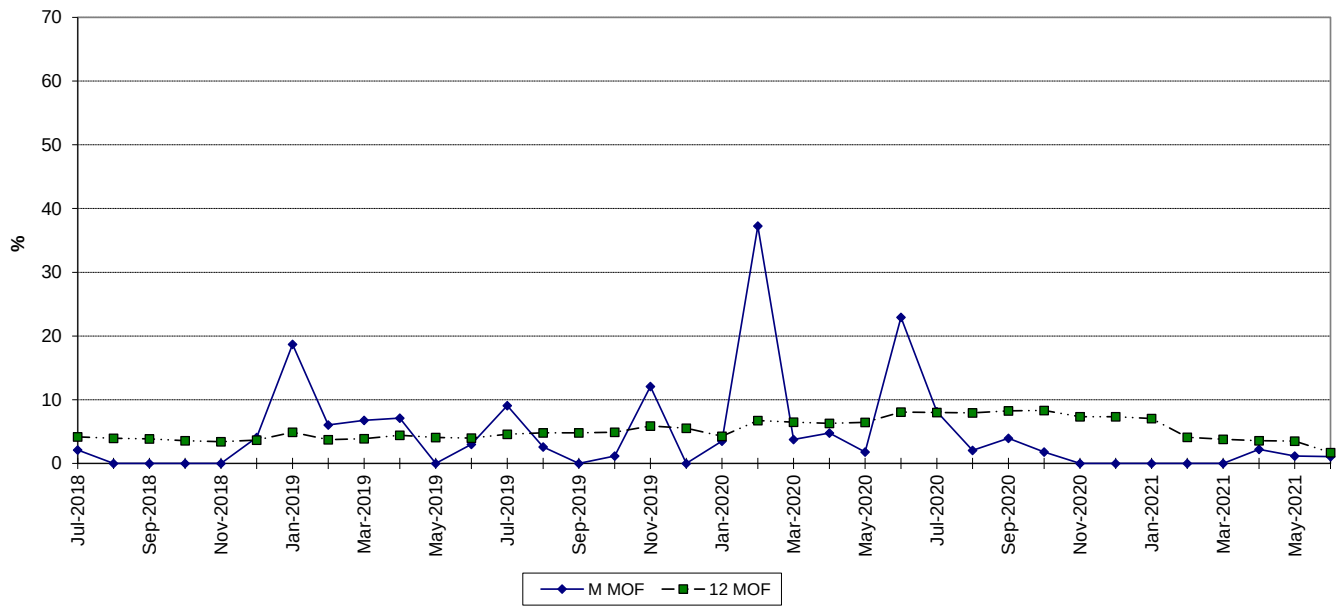
MAINTENANCE OUTAGE FACTOR



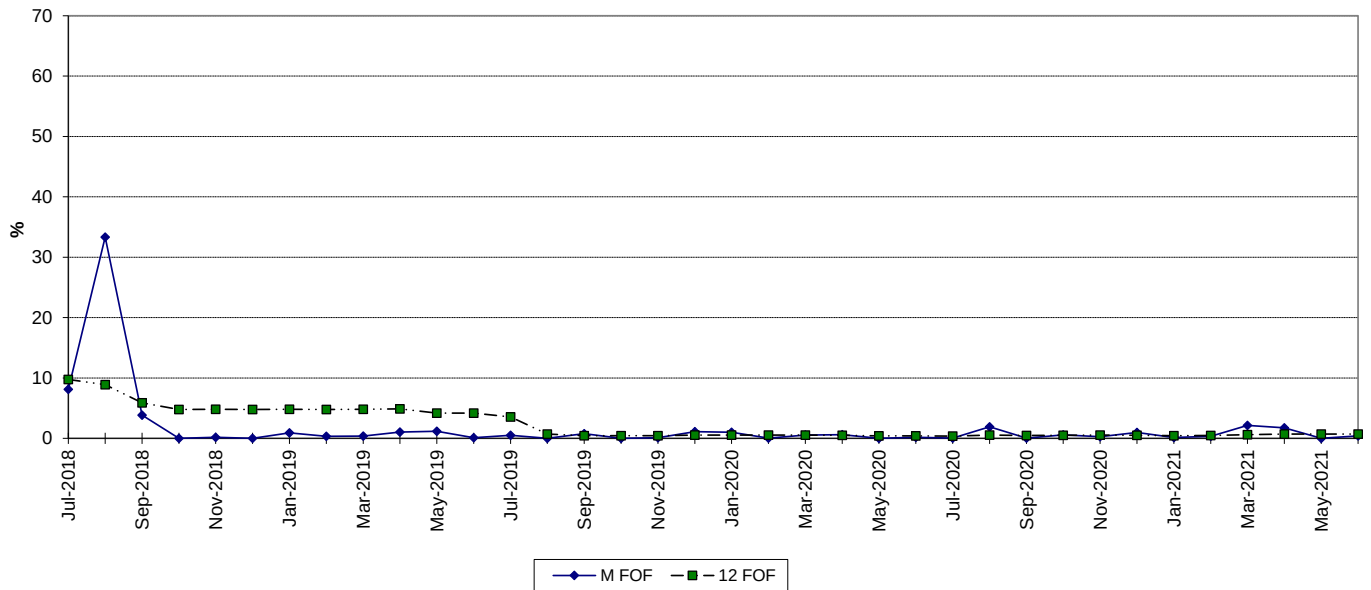
MARTIN 8
FORCED OUTAGE FACTOR



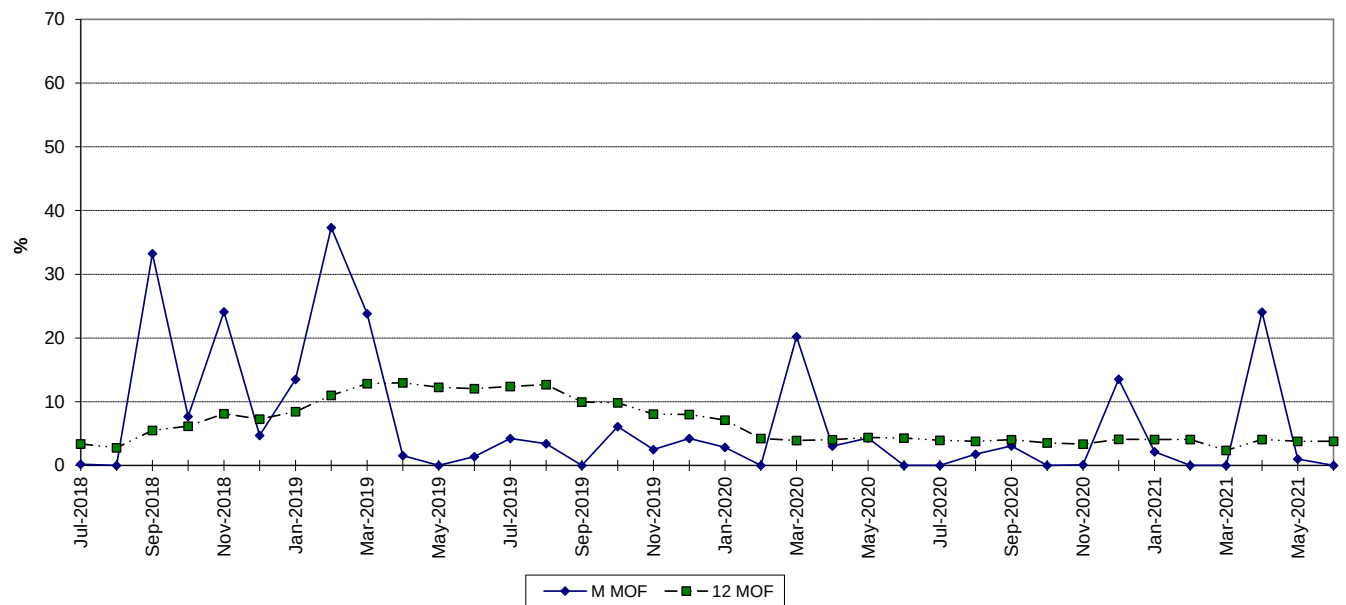
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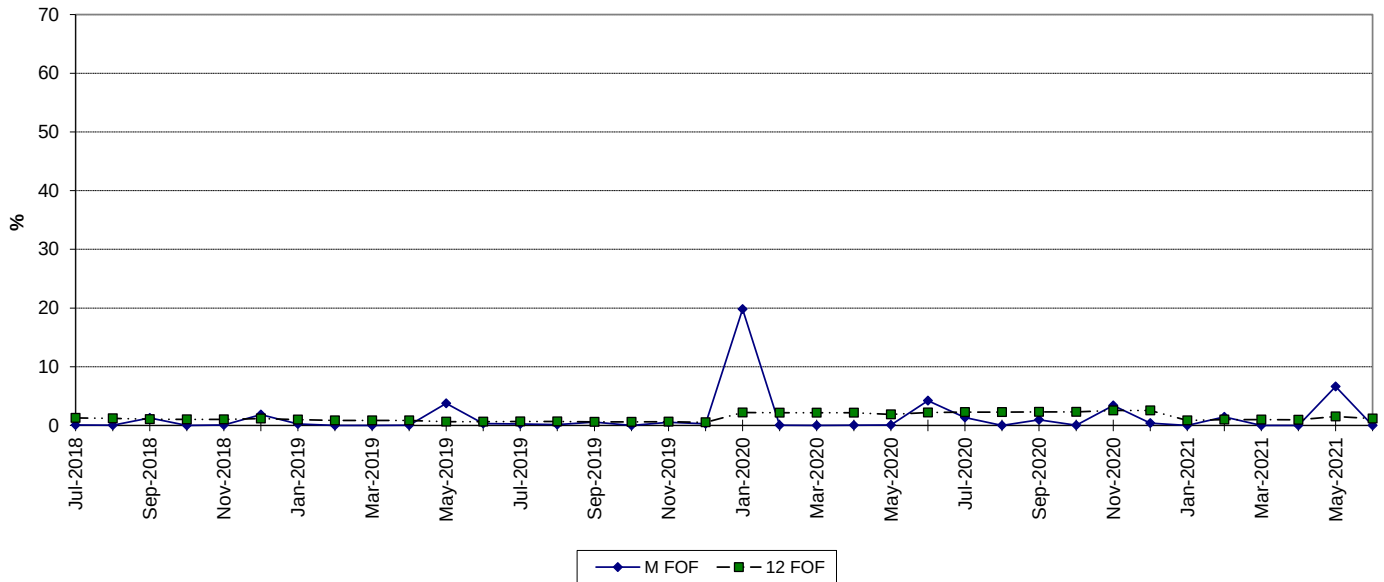
PORT EVERGLADES 5 FORCED OUTAGE FACTOR



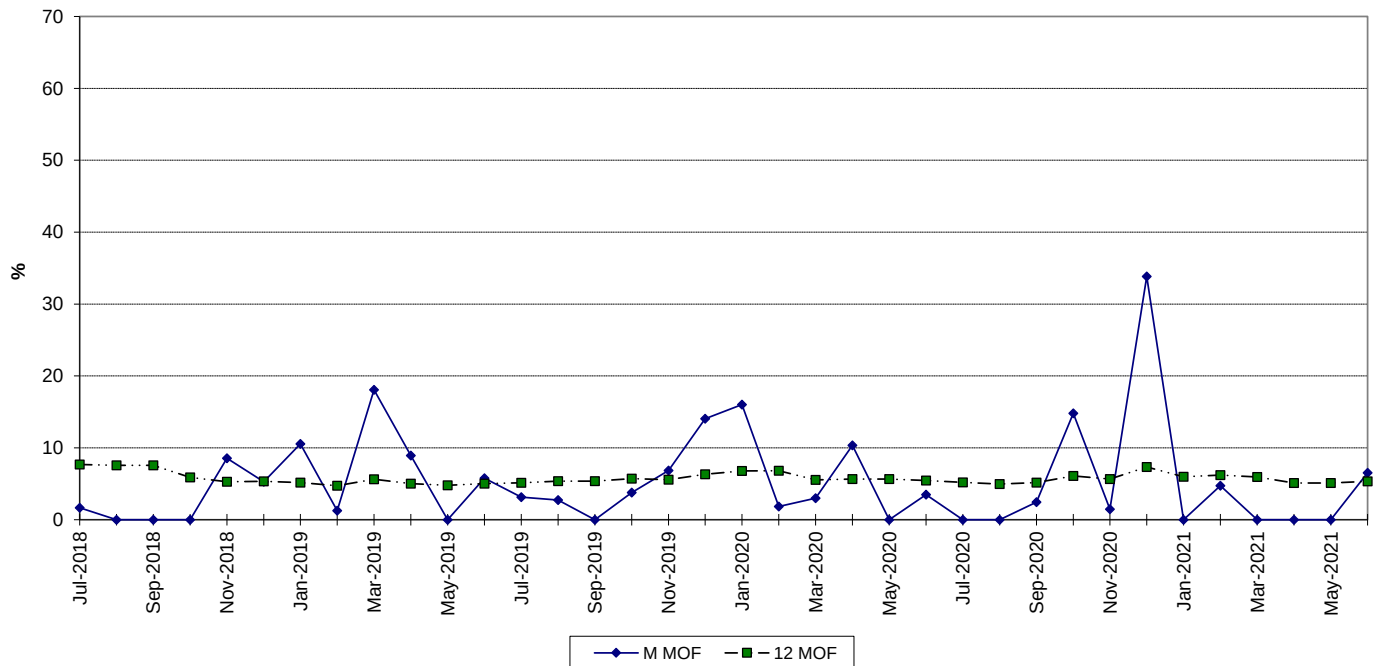
MAINTENANCE OUTAGE FACTOR



RIVIERA 5 FORCED OUTAGE FACTOR

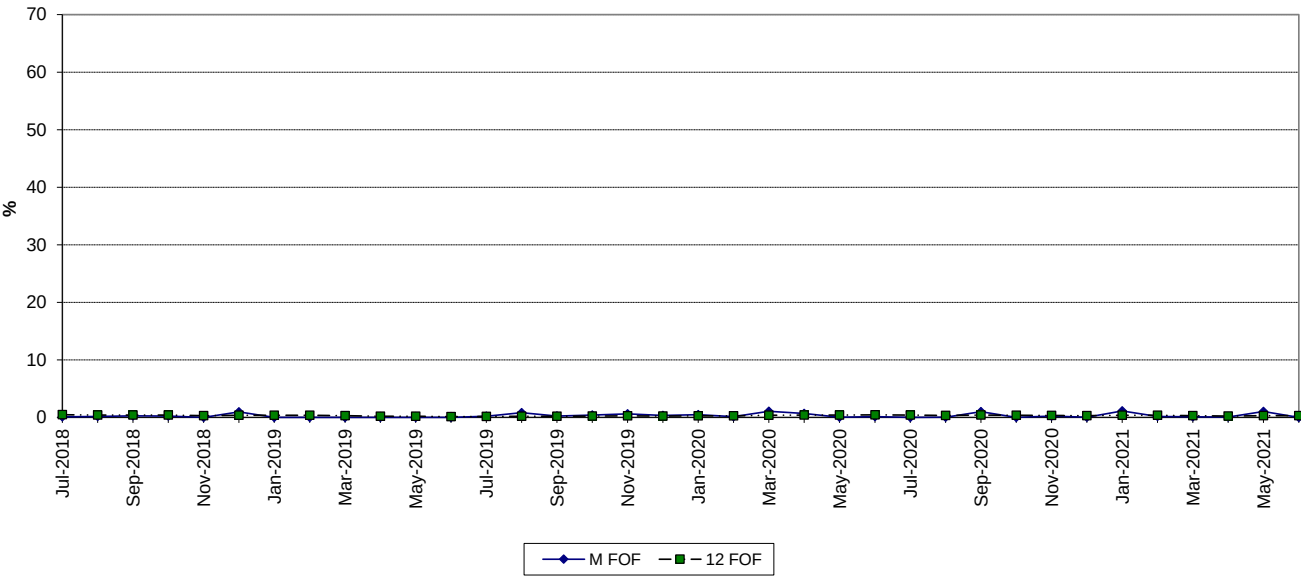


MAINTENANCE OUTAGE FACTOR

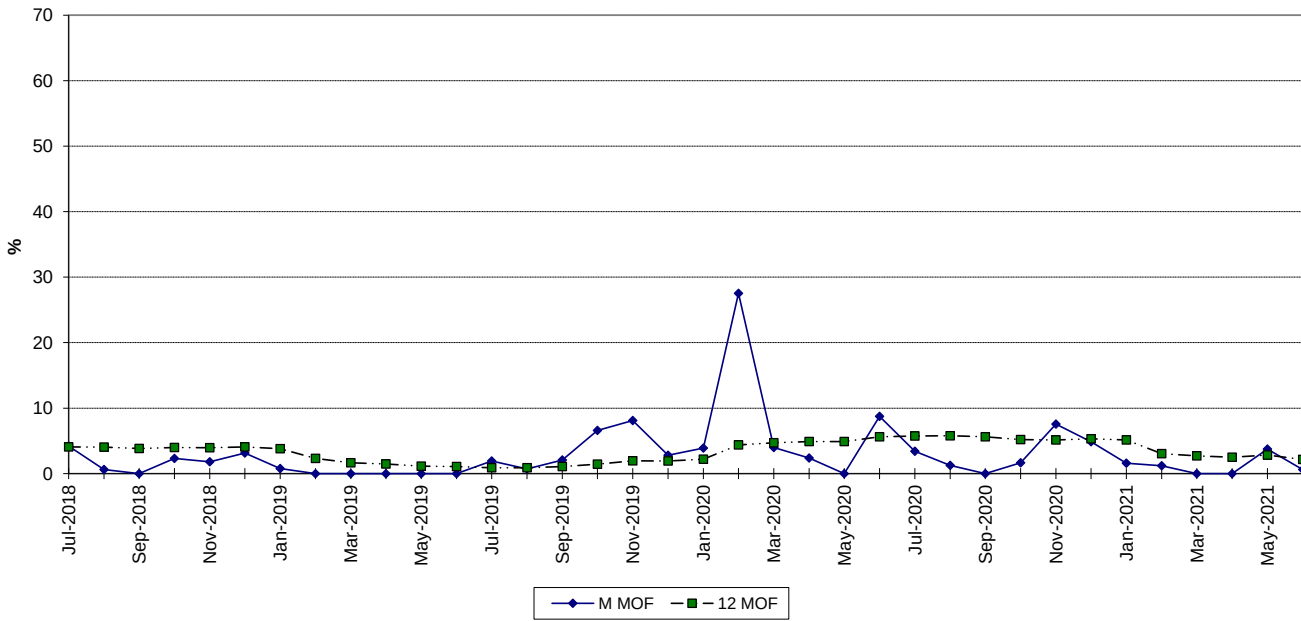


SANFORD 5

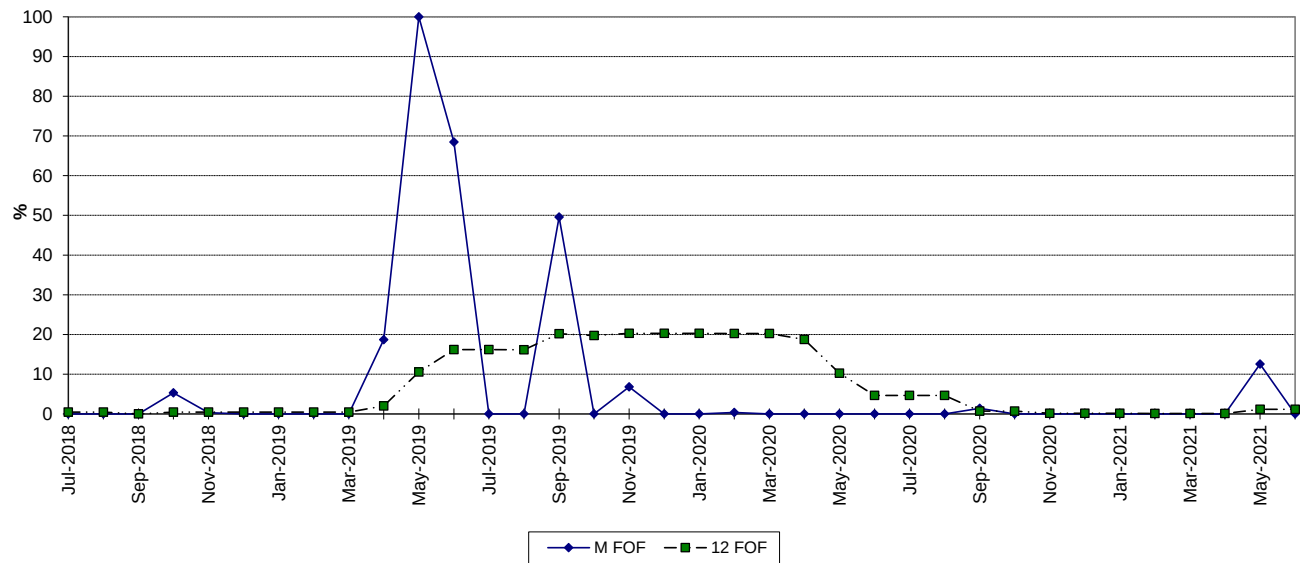
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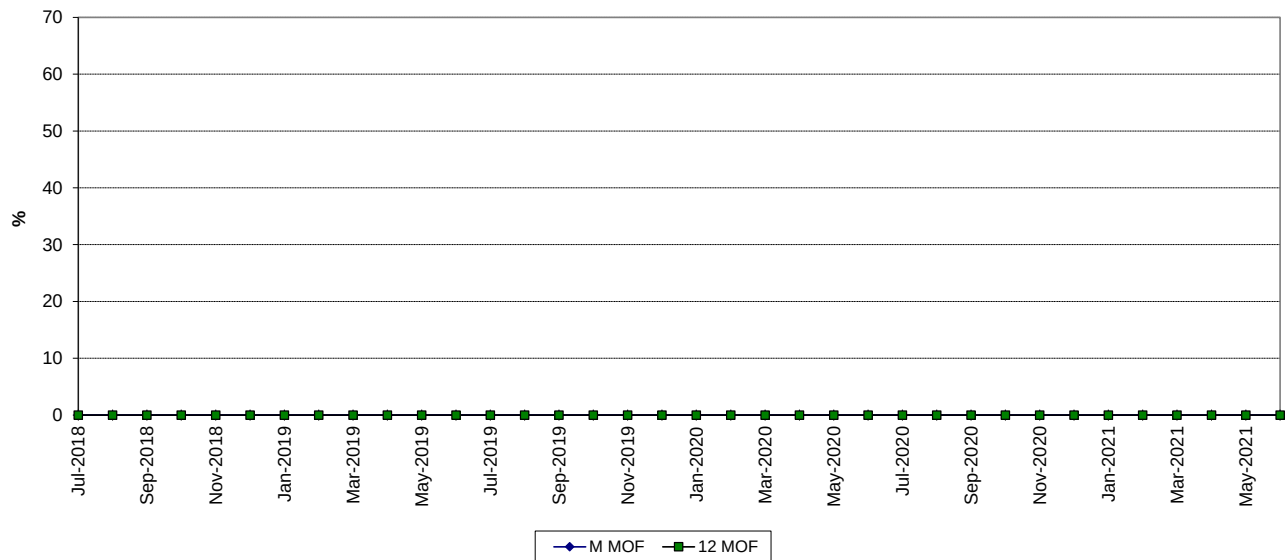
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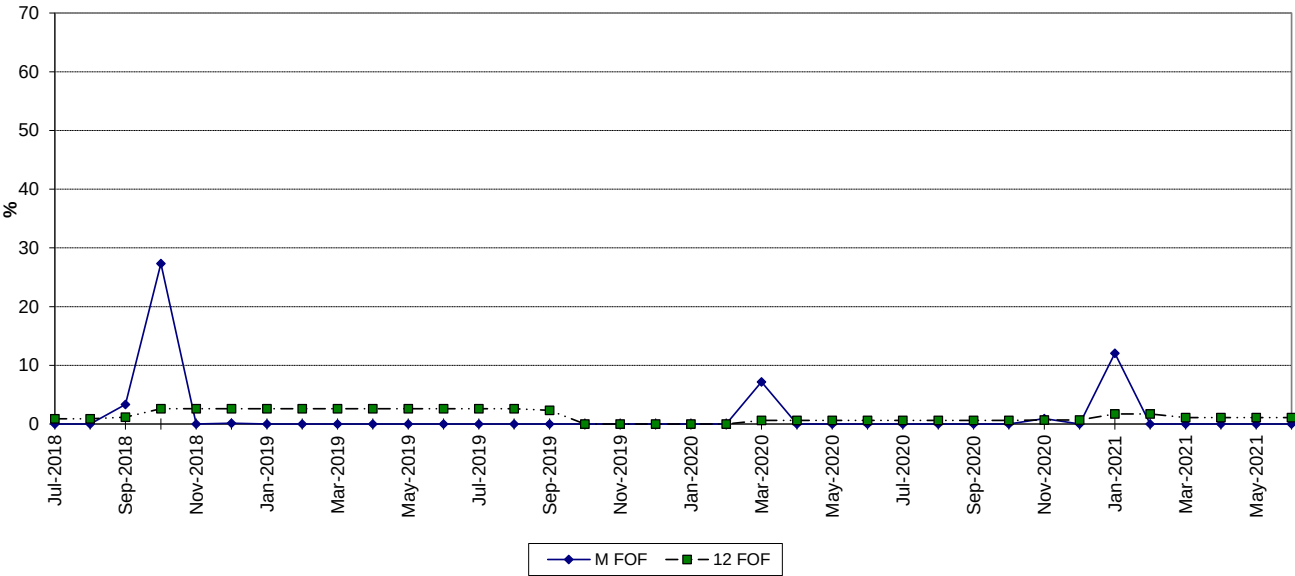
ST. LUCIE 1 FORCED OUTAGE FACTOR



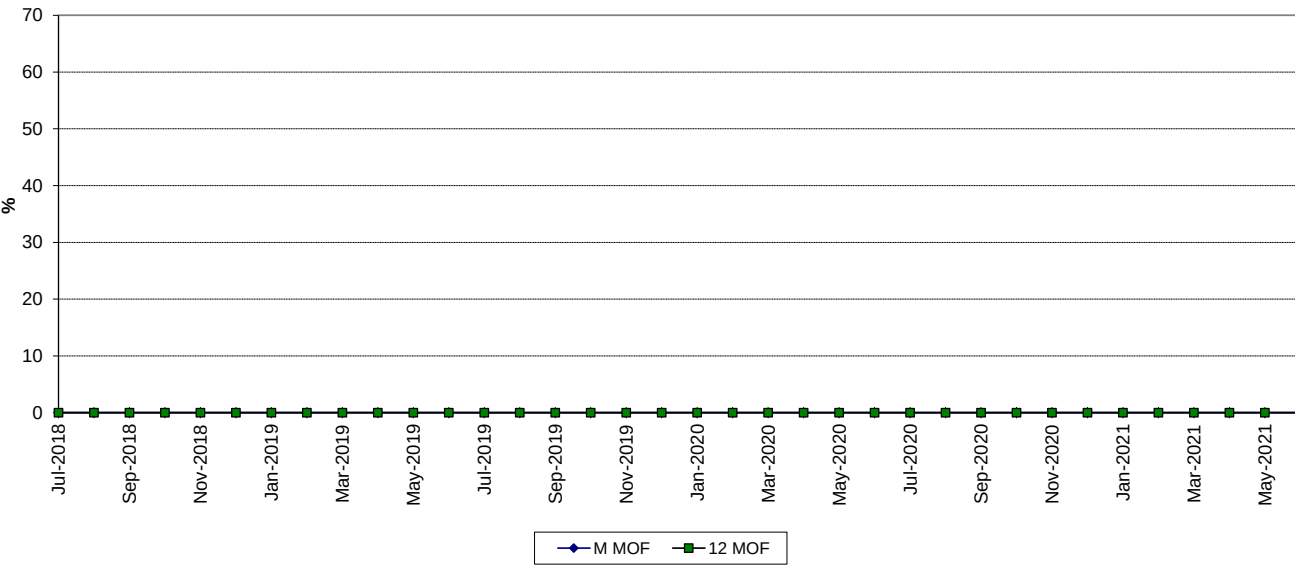
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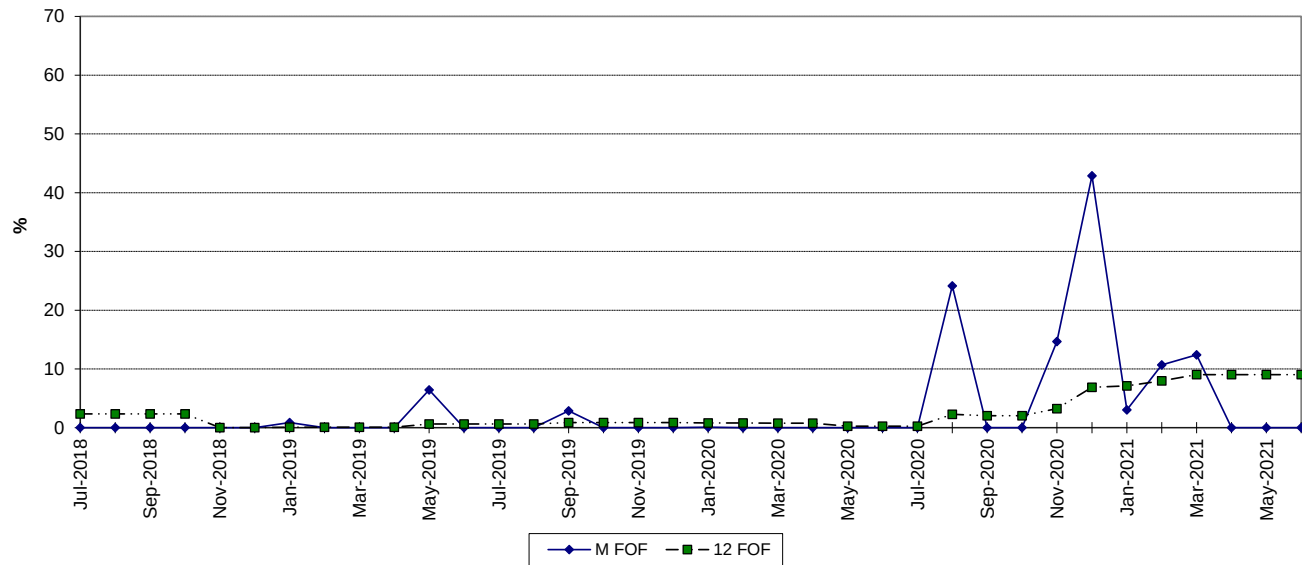
ST. LUCIE 2
FORCED OUTAGE FACTOR



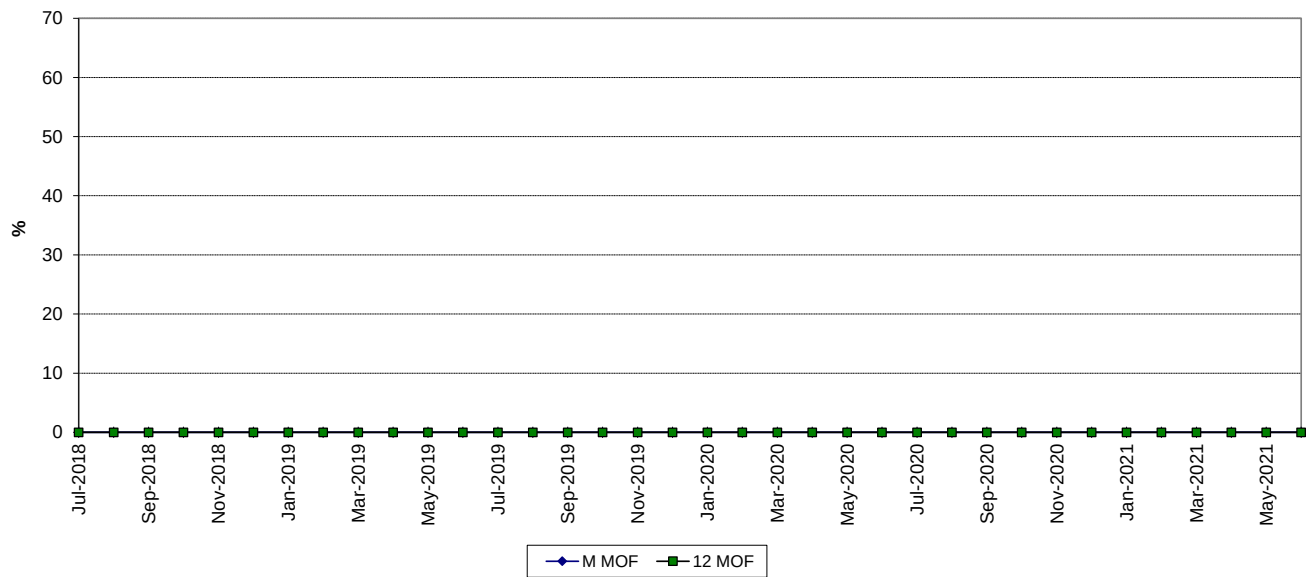
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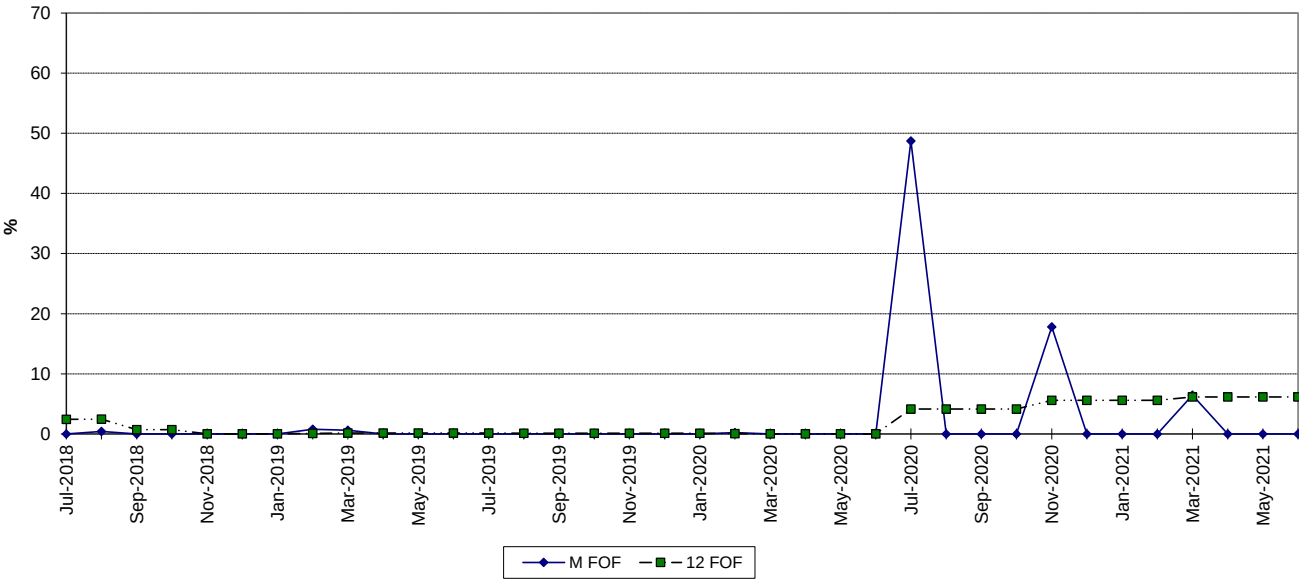
TURKEY POINT 3
FORCED OUTAGE FACTOR



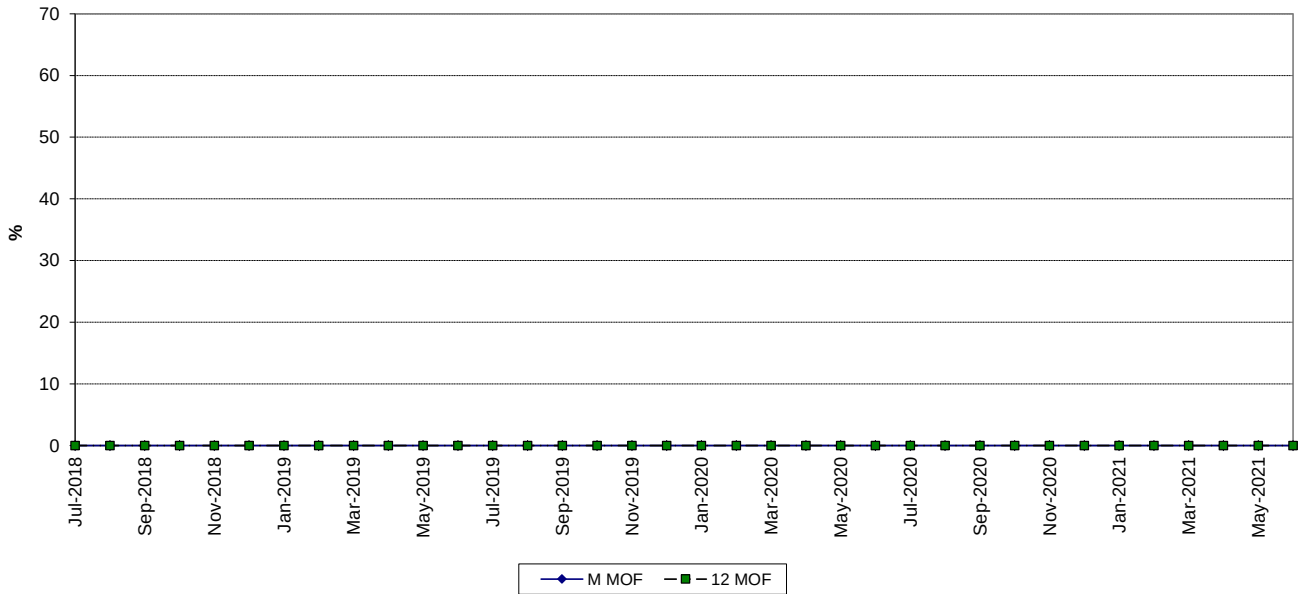
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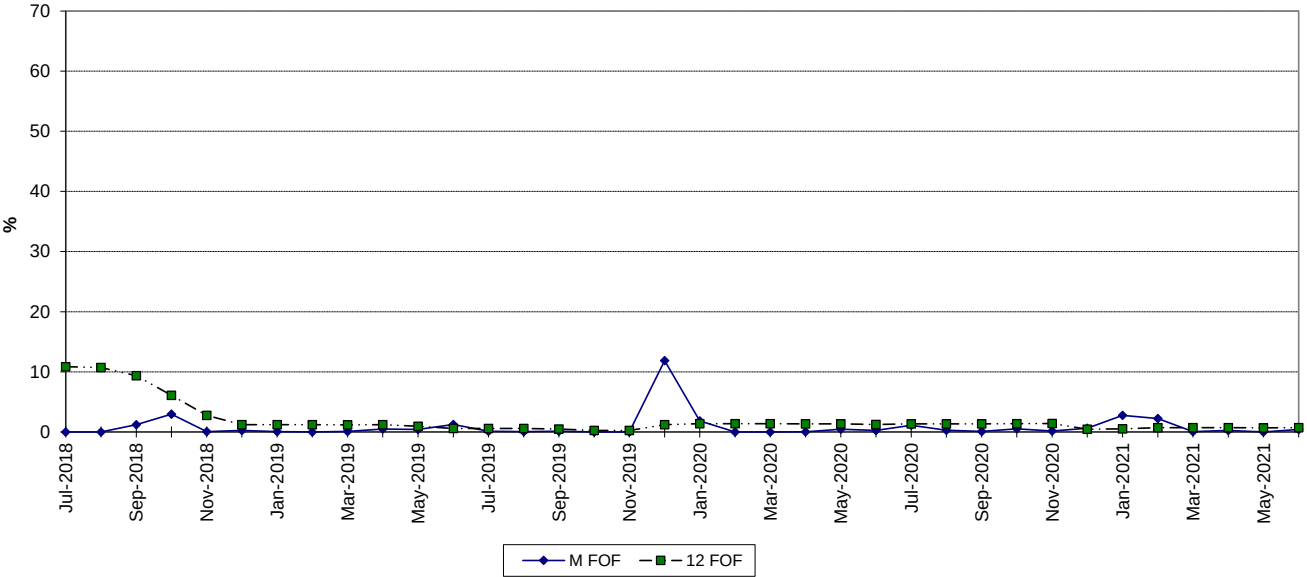
TURKEY POINT 4
FORCED OUTAGE FACTOR



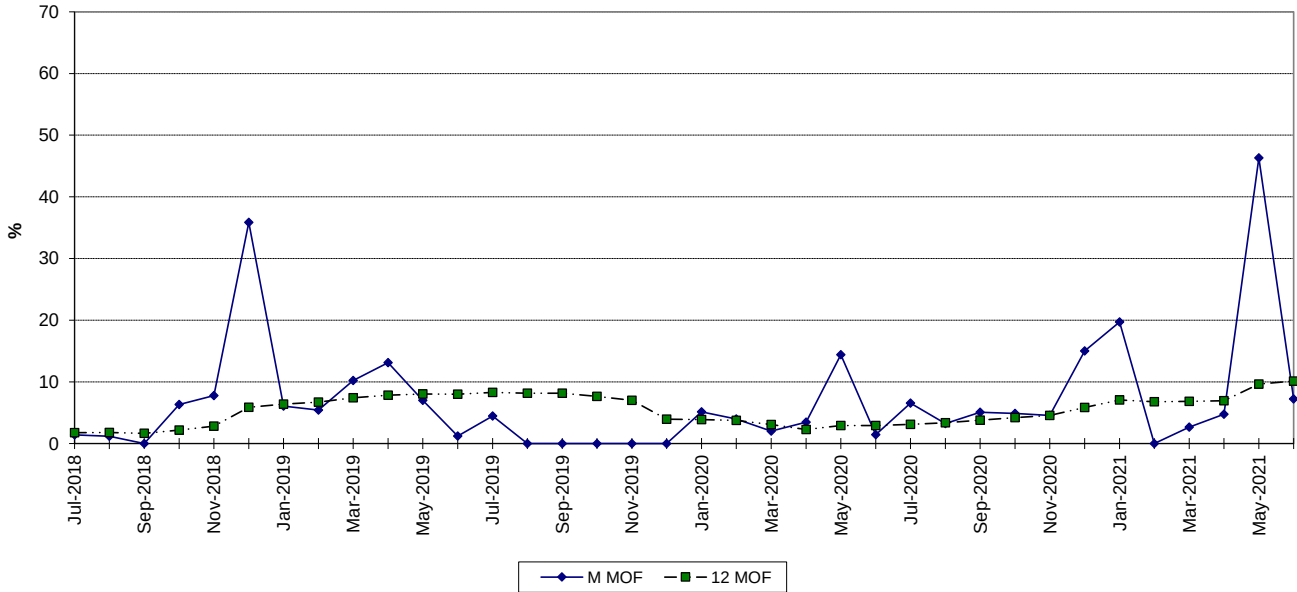
MAINTENANCE OUTAGE FACTOR



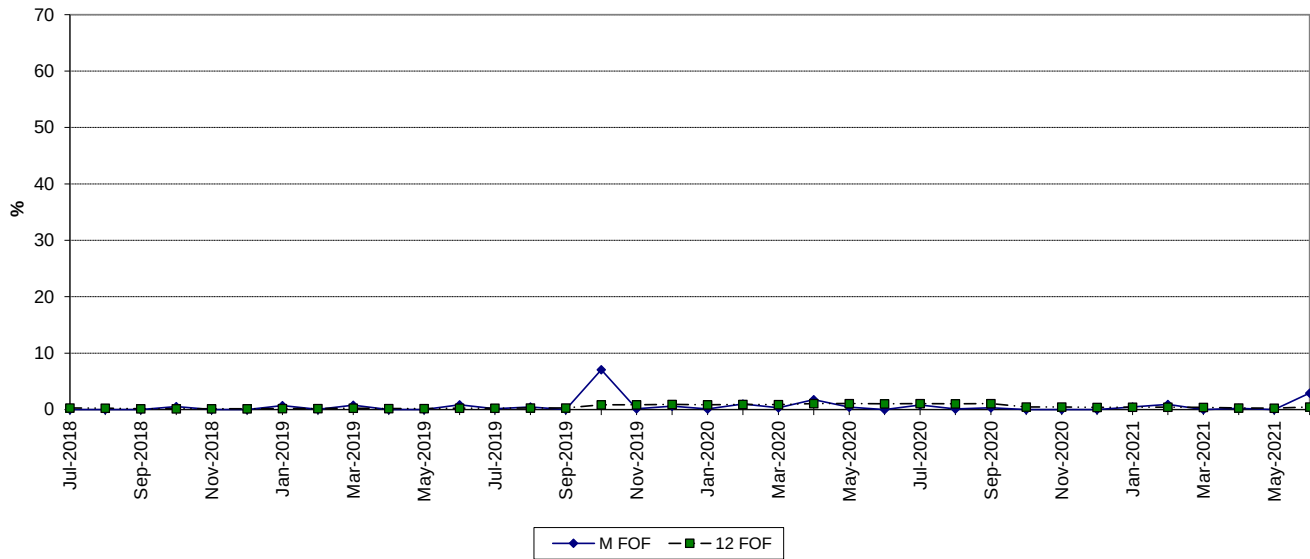
TURKEY POINT 5
FORCED OUTAGE FACTOR



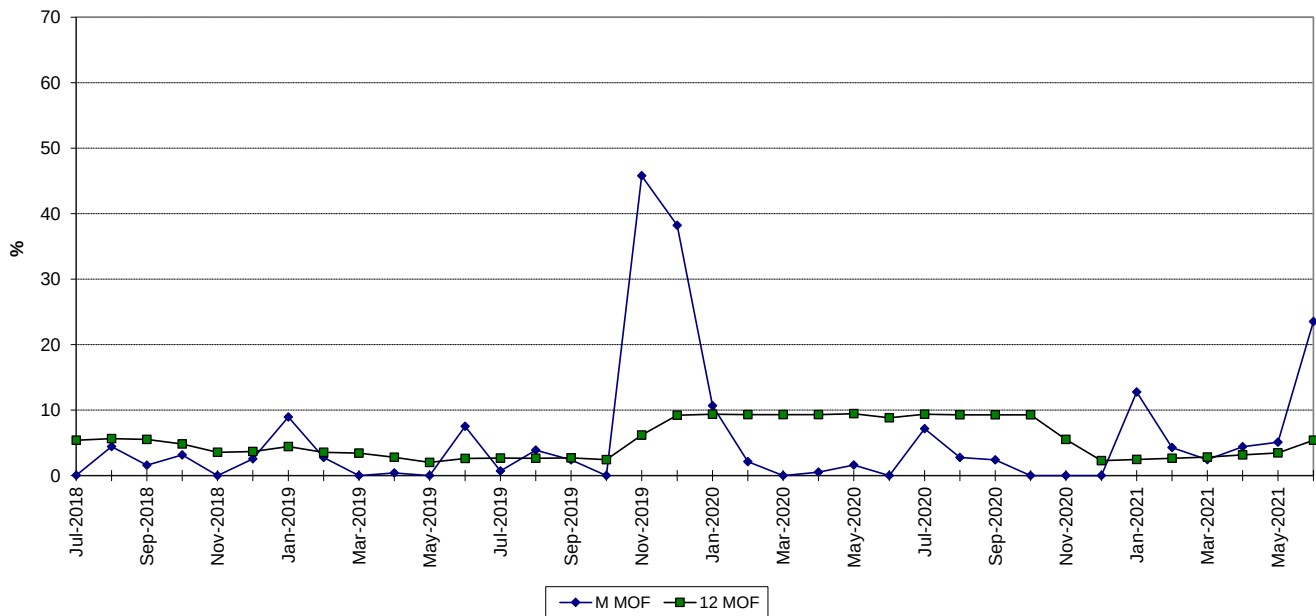
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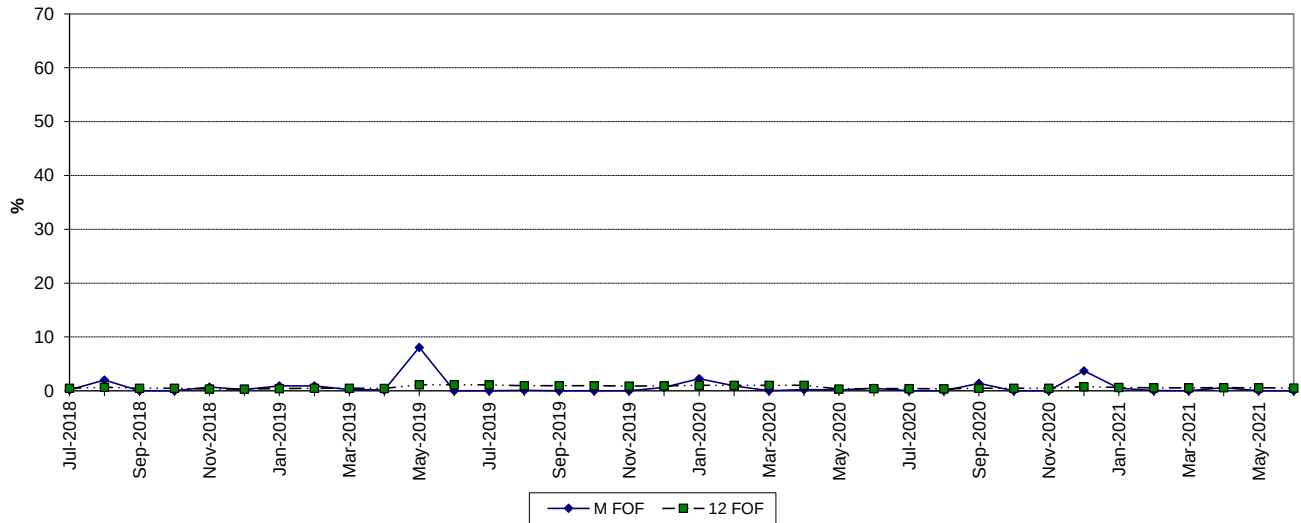
WEST COUNTY 1 FORCED OUTAGE FACTOR



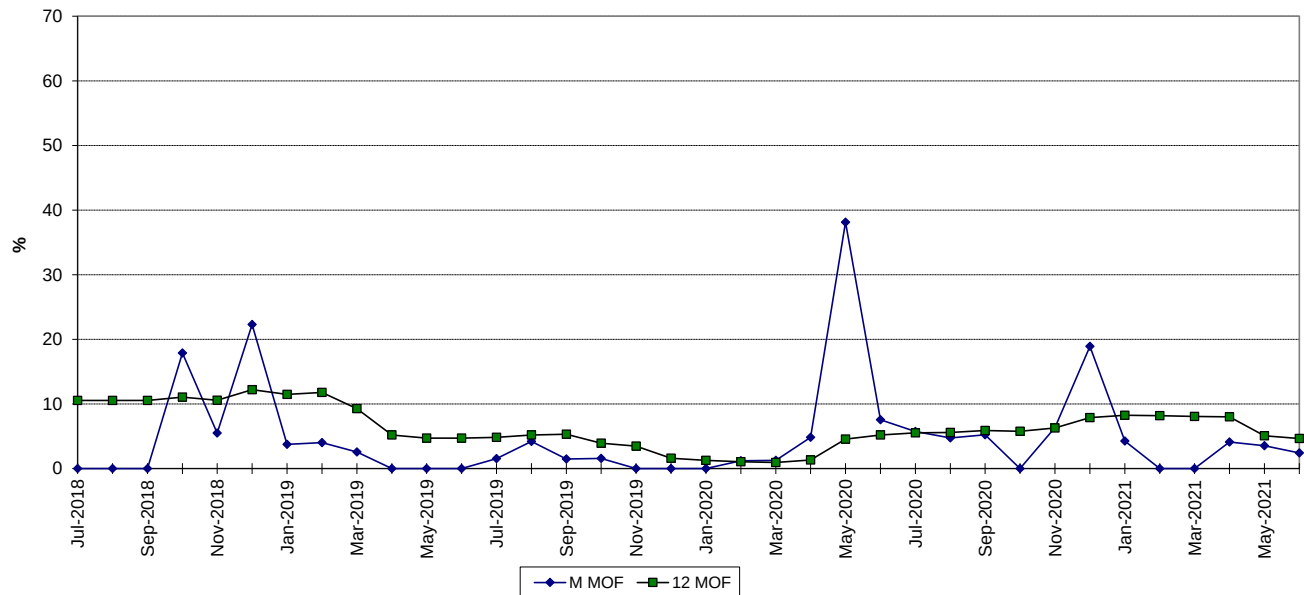
MAINTENANCE OUTAGE FACTOR



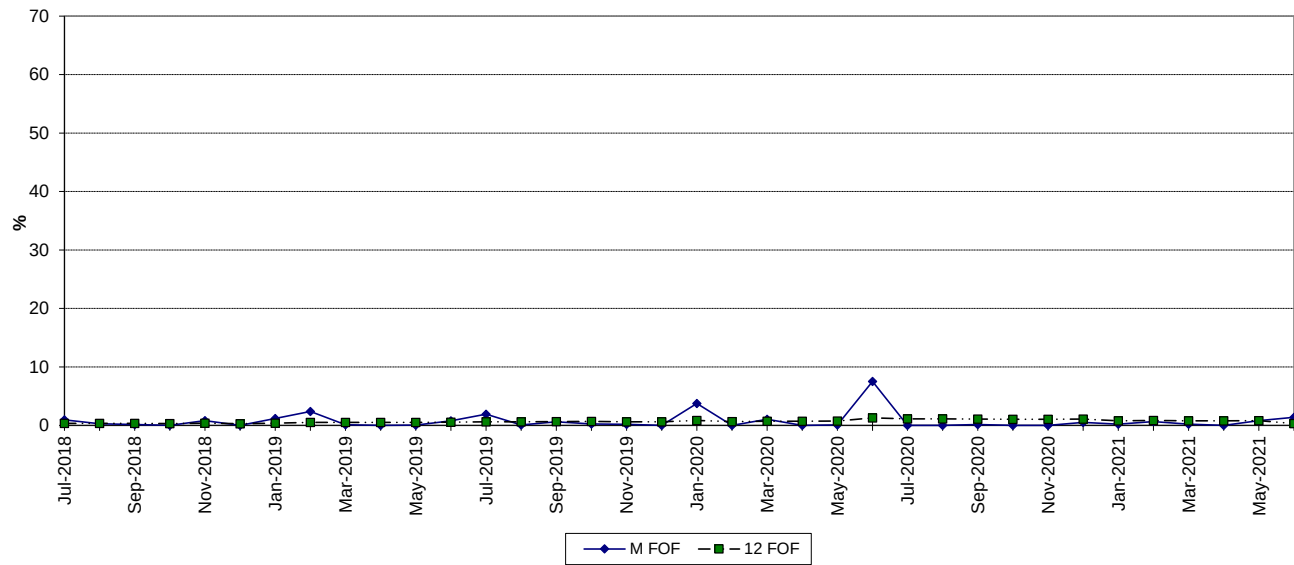
WEST COUNTY 2 FORCED OUTAGE FACTOR



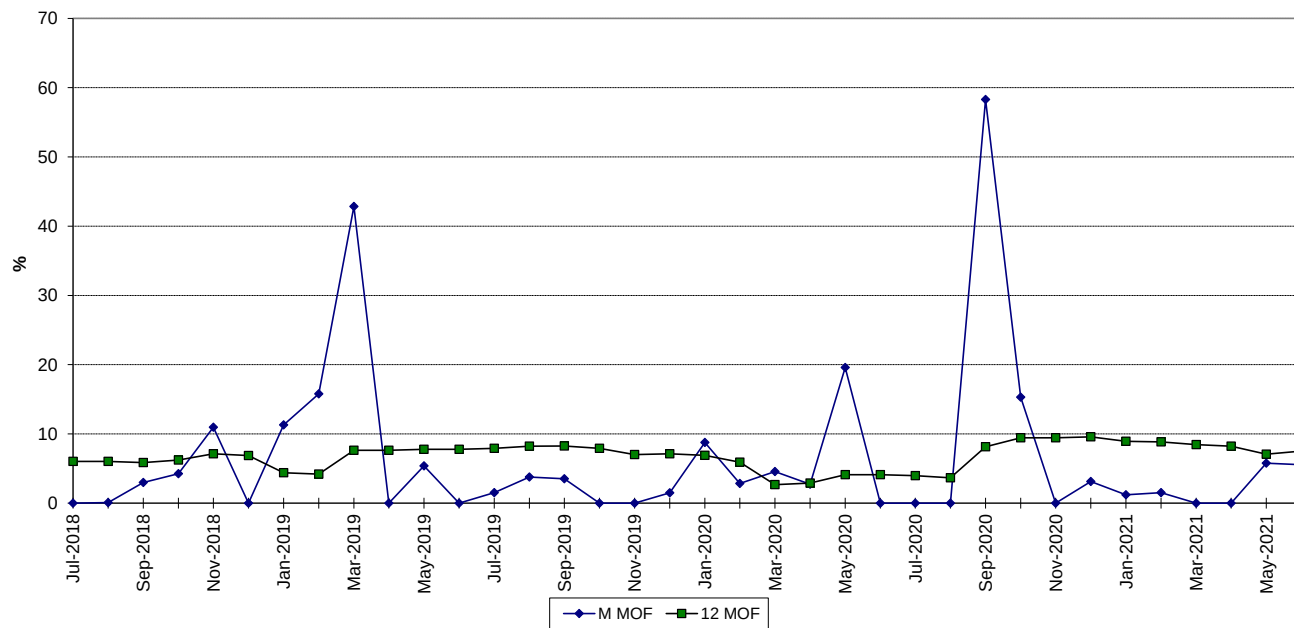
MAINTENANCE OUTAGE FACTOR



WEST COUNTY 3 FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2022

PLANT/UNIT	PLAN OUTAGE	REASON FOR OUTAGE	LR MW*
Cape Canaveral 3	02/15/2022 - 03/22/2022	PCC 31 Hot Gas Path	275
Cape Canaveral 3	03/17/2022 - 03/27/2022	PCC ST Balance of Plant (BOP)	1,326
Cape Canaveral 3	03/23/2022 - 04/24/2022	PCC 32 Hot Gas Path	275
Cape Canaveral 3	04/24/2022 - 05/26/2022	PCC 33 Hot Gas Path (HGP)	271
Ft. Myers 2	11/17/2022 - 11/24/2022	PFM 2A Heat Recovery Steam Generator (HRSG) Inspection	193
Ft. Myers 2	11/30/2022 - 12/07/2022	PFM 2B & 2C HRSG Inspections	386
Ft. Myers 2	12/08/2022 - 12/15/2022	PFM 2D & 2E HRSG Inspections	386
Manatee 3	04/07/2022 - 05/05/2022	PMT ST Steam Turbine Maintenance	1,223
Manatee 3	10/01/2022 - 10/24/2022	PMT 3A Hot Gas Path Outage	190
Manatee 3	10/12/2022 - 11/04/2022	PMT 3C Hot Gas Path Outage	190
Manatee 3	04/01/2022 - 04/24/2022	PMT 3D Hot Gas Path Outage	190
Manatee 3	04/24/2022 - 05/17/2022	PMT 3B Hot Gas Path Outage	190
Martin 8	03/28/2022 - 04/07/2022	PMR 8 ST Steam Turbine Maintenance	1,258
Martin 8	06/01/2022 - 06/24/2022	PMR 8B Hot Gas Path Outage	189
Martin 8	11/15/2022 - 12/12/2022	PMR 8A Hot Gas Path Outage	198
Port Everglades 5	10/10/2022 - 11/14/2022	PPE ST Steam Turbine Maintenance	1,254
Riviera 5	03/01/2022 - 03/11/2022	PRV 5 ST and CTs 1-3 Maintenance	1,326
Sanford 5	02/16/2022 - 02/26/2022	Distributed Control System (DCS) Minor	1,192
St. Lucie 1	09/03/2022 - 10/03/2022	Refueling	981
St. Lucie 2	NONE		n/a
Turkey Point 3	NONE		n/a
Turkey Point 4	03/12/2022 - 04/10/2022	Refueling	866
Turkey Point 5	12/08/2022 - 12/15/2022	PTF 5 ST and CTs A-D Maintenance	1,294
West County 1	09/15/2022 - 11/04/2022	PWC 1C CT Major Outage	244
West County 1	11/04/2022 - 12/24/2022	PWC 1A CT Major Outage	253
West County 2	02/15/2022 - 04/26/2022	PWC ST Steam Turbine Major and CT 2A Major Outage	1,248
West County 2	04/01/2022 - 05/21/2022	PWC 2C CT Major Outage	244
West County 2	05/21/2022 - 07/10/2022	PWC 2B CT Major Outage	244
West County 3	11/27/2022 - 12/07/2022	PWC ST BOP and CTs A-C Maintenance	1,254

*Approximate load reduction MW are based on the unit's estimated MW rating at the start of the outage period

FLORIDA POWER & LIGHT COMPANY
2019 OKEECHOBEE CLEAN ENERGY CENTER (OCEC) LSA
FIRST YEAR ANNUALIZED REVENUE REQUIREMENT (\$000)

Line No.	(1)	(2)	(3)
	Description	Reference	Amount (\$000) ⁽¹⁾
1	Jurisdictional Adjusted Rate Base	Page 2	\$ 1,059,045
2	Rate of Return on Rate Base	Note 3	8.27%
3	Required Jurisdictional Net Operating Income	Line 1 x Line 2	\$ 87,618
4	Required Net Operating Income		87,618
5	Jurisdictional Adjusted Net Operating Income (Loss)	Note 4	\$ (33,998)
6	Net Operating Income Deficiency (Excess)	Line 4 - Line 5	121,616
7	Net Operating Income Multiplier	Note 5	1.63024
8	Revenue Requirement ⁽¹⁾	Line 6 x Line 7	\$ 198,264
9	Revenue Increase approved per the Settlement Agreement ⁽²⁾		\$ 200,000
10	Difference in Revenue Requirement	Line 8 - Line 9	\$ (1,736)

11 NOTES:

12 ⁽¹⁾ Represents the recalculated revenue requirements per paragraph 9 of FPL's 2016 Rate Case Settlement Agreement approved by the FPSC in Order No. PSC-16-0560-AS-EI, Docket No. 20160061-EI.

13 ⁽²⁾ Represents the approved rate increase for the OCEC LSA in FPL's 2016 Rate Case Settlement Agreement.

14 ⁽³⁾ Represents the weighted average cost of capital from page 12 of FPL witness Ousdahl's Exhibit KO-20 in Docket No. 20160021-EI revised to incorporate a mid-point ROE of 10.55% as required under FPL's 2016 Rate Case Settlement Agreement.

15 ⁽⁴⁾ Represents the net operating income reflected on page 9 of FPL witness Ousdahl's Exhibit KO-20 in Docket No. 20160021-EI.

16 ⁽⁵⁾ Represents the net operating income multiplier reflected on page 9 of FPL witness Ousdahl's Exhibit KO-20 in Docket No. 20160021-EI.

FLORIDA POWER & LIGHT COMPANY
2019 OKEECHOBEE CLEAN ENERGY CENTER (OCEC) LSA
JURISDICTIONAL ADJUSTED RATE BASE
13-MONTH AVERAGE

Line No.	(1) Description	Initial OCEC LSA ⁽¹⁾			Final OCEC LSA		
		(2) Total Company (\$000)	(3) FPSC Jurisdictional (\$000)	(4) Jurisdictional Factor	(5) Total Company (\$000)	(6) FPSC Jurisdictional (\$000)	(7) Jurisdictional Factor
1							
2	<u>PLANT IN SERVICE:</u>						
3							
4	ELECTRIC PLANT IN SERVICE - OTHER PRODUCTION	\$ 1,145,575	\$ 1,089,767	0.951284	\$ 1,146,747 ⁽²⁾	\$ 1,090,882	0.951284
5							
6	ELECTRIC PLANT IN SERVICE - TRANSMISSION	\$ 57,012	\$ 51,239	0.898735	\$ 50,570 ⁽²⁾	\$ 45,449	0.898735
7	ELECTRIC PLANT IN SERVICE - TRANSMISSION - GSU's	\$ 25,460	\$ 24,220	0.951284	25,939 ⁽²⁾	24,676	0.951284
8	TOTAL ELECTRIC PLANT IN SERVICE - TRANSMISSION	\$ 82,473	\$ 75,459	0.916551	\$ 76,509 ⁽²⁾	\$ 70,125	0.916551
9							
10							
11	TOTAL PLANT IN SERVICE	\$ 1,228,048	\$ 1,165,226	0.949111	\$ 1,223,256 ⁽²⁾	\$ 1,161,006	0.949111
12							
13	<u>ACCUMULATED PROVISION FOR DEPRECIATION:</u>						
14							
15							
16	ACCUM PROVISION FOR DEPRECIATION - OTHER PRODUCTION				\$ 20,764 ⁽¹⁾	\$ 19,752	0.951284
17							
18	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION				\$ 565 ⁽¹⁾	\$ 508	0.898735
19	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION - GSU				336 ⁽¹⁾	320	0.951284
20	TOTAL ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION				\$ 901 ⁽¹⁾	\$ 827	0.918336
21							
22	TOTAL ACCUMULATED PROVISION FOR DEPRECIATION				\$ 21,665 ⁽¹⁾	\$ 20,580	0.949914
23							
24							
25	ACCUMULATED DEFERRED INCOME TAXES				\$ (85,747) ⁽¹⁾	\$ (81,382)	0.949097
26							
27	TOTAL RATE BASE				<u>\$ 1,115,845</u>	<u>\$ 1,059,045</u>	<u>0.949097</u>
28							
29	<u>NOTES:</u>						
30	⁽¹⁾ Amounts reflected are from the recalculated 2019 OCEC LSA Rate Base per FPL witness Ousdahl's Exhibit KO-20 filed in her rebuttal testimony on August 1, 2016 in Docket No. 20160021-EI.						
31	⁽²⁾ Amount represents actual final capital costs.						

FLORIDA POWER & LIGHT COMPANY
2019 SoBRA PROJECT
FIRST YEAR ANNUALIZED REVENUE REQUIREMENT⁽¹⁾

Line No	(1) Description	(2) Page Reference	(3) Initial SoBRA Amount (\$000)	(4) Final SoBRA Amount (\$000)	(5) True-up Amount (\$000)
1	Jurisdictional Adjusted Rate Base	Page 2	\$ 372,761	\$ 372,515	\$ (246)
2	Rate of Return on Rate Base		8.15%	8.15%	8.15%
3	Required Jurisdictional Net Operating Income	Line 1 x Line 2	\$ 30,379	\$ 30,359	\$ (20)
4	Required Net Operating Income		\$ (8,154)	\$ (8,154)	0
5	Net Operating Income Deficiency (Excess)	Line 3 - Line 4	\$ 38,533	\$ 38,513	\$ (20)
6	Net Operating Income Multiplier ⁽²⁾		1.34135	1.34135	1.34135
7	Revenue Requirement	Line 5 x Line 6	\$ 51,685	\$ 51,659	\$ (26.890)

8

9 NOTES:

10 ⁽¹⁾ Represents the revenue requirement for the projected 12-month period for the 2019 SoBRA Project.

11 ⁽²⁾ Represents the net operating income multiplier from page 9 of Exhibit KO-20, Docket No. 20160021-EI, revised to incorporate the 21% corporate federal income tax rate per the Tax Cuts and Jobs Act of 2017.

FLORIDA POWER & LIGHT COMPANY
2019 SoBRA PROJECT
JURISDICTIONAL ADJUSTED RATE BASE
13-MONTH AVERAGE

Line No.	(1) Description	(2) Total Company (\$000)	Initial SoBRA ⁽¹⁾		(4) Jurisdictional Factor	Final SoBRA ⁽²⁾		(7) Jurisdictional Factor
			(3) FPSC Jurisdictional (\$000)			(5) Total Company (\$000)	(6) FPSC Jurisdictional (\$000)	
1								
2	<u>PLANT IN SERVICE:</u>							
3								
4	ELECTRIC PLANT IN SERVICE - OTHER PRODUCTION	\$ 351,451	\$ 331,705		0.943814	\$ 349,022	\$ 329,412	0.943814
5								
6	ELECTRIC PLANT IN SERVICE - TRANSMISSION	\$ 24,743	\$ 22,237		0.898719	\$ 24,963	\$ 22,435	0.898719
7	ELECTRIC PLANT IN SERVICE - TRANSMISSION - GSU's	3,639	3,457		0.950031	5,103	4,848	0.950031
8	TOTAL ELECTRIC PLANT IN SERVICE - TRANSMISSION	\$ 28,382	\$ 25,694		0.905297	\$ 30,065	\$ 27,282	0.905297
9								
10	NON-DEPRECIABLE PROPERTY (LAND)	\$ 33,230	\$ 31,363		0.943814	\$ 33,716	\$ 31,821	0.943814
11								
12	TOTAL PLANT IN SERVICE	\$ 413,063	\$ 388,762		0.941168	\$ 412,804	\$ 388,516	0.941168
13								
14	<u>ACCUMULATED PROVISION FOR DEPRECIATION:</u>							
15								
16								
17	ACCUM PROVISION FOR DEPRECIATION - OTHER PRODUCTION	\$ 5,922	\$ 5,589		0.943814	\$ 5,922	\$ 5,589	0.943814
18								
19	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION	\$ 247	\$ 222		0.898719	\$ 247	\$ 222	0.898719
20	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION - GSU	48	46		0.950031	48	46	0.950031
21	TOTAL ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION	\$ 295	\$ 268		0.907060	\$ 295	\$ 268	0.907060
22								
23	TOTAL ACCUMULATED PROVISION FOR DEPRECIATION	\$ 6,217	\$ 5,857		0.942068	\$ 6,217	\$ 5,857	0.942068
24								
25								
26	ACCUMULATED DEFERRED INCOME TAXES	\$ (10,778)	\$ (10,144)		0.941154	\$ (10,778)	\$ (10,144)	0.941154
27								
28	TOTAL RATE BASE	\$ 396,068	\$ 372,761		0.941154	\$ 395,808	\$ 372,515	0.941154
29								
30								

31 NOTES:

32 (1) Reflects projected rate base included in the Initial SoBRA calculation approved by the Commission in Order No. PSC-20180610, Docket No.20180001-EI (issued on December 26, 2018).

33 (2) Reflects rate base included in the initial SoBRA in column 3, except projected plant in service has been replaced with final actual plant in service.

FLORIDA POWER & LIGHT COMPANY
2020 SoBRA PROJECT
FIRST YEAR ANNUALIZED REVENUE REQUIREMENT⁽¹⁾

Line No	(1) Description	(2) Page Reference	(3) Initial SoBRA Amount (\$000)	(4) Final SoBRA Amount (\$000)	(5) True-up Amount (\$000)
1	Jurisdictional Adjusted Rate Base	Page 2	\$ 363,770	\$ 362,802	\$ (968)
2	Rate of Return on Rate Base		8.26%	8.26%	8.26%
3	Required Jurisdictional Net Operating Income	Line 1 x Line 2	\$ 30,065	\$ 29,985	\$ (80)
4	Required Net Operating Income		\$ (7,577)	\$ (7,577)	0
5	Net Operating Income Deficiency (Excess)	Line 3 - Line 4	\$ 37,642	\$ 37,562	\$ (80)
6	Net Operating Income Multiplier ⁽²⁾		1.34135	1.34135	1.34135
7	Revenue Requirement	Line 5 x Line 6	\$ 50,491	\$ 50,384	\$ (107.294)

8

9 NOTES:

10 ⁽¹⁾ Represents the revenue requirement for the projected 12-month period for the 2020 SoBRA Project.

11 ⁽²⁾ Represents the net operating income multiplier from page 9 of Exhibit KO-20, Docket No. 20160021-EI, revised to incorporate the 21% corporate federal income tax rate per the Tax Cuts and Jobs Act of 2017.

FLORIDA POWER & LIGHT COMPANY
2020 SoBRA PROJECT
JURISDICTIONAL ADJUSTED RATE BASE
13-MONTH AVERAGE

Line No.	(1) Description	Initial SoBRA ⁽¹⁾			Final SoBRA ⁽²⁾		
		(2) Total Company (\$000)	(3) FPSC Jurisdictional (\$000)	(4) Jurisdictional Factor	(5) Total Company (\$000)	(6) FPSC Jurisdictional (\$000)	(7) Jurisdictional Factor
1							
2	<u>PLANT IN SERVICE:</u>						
3							
4	ELECTRIC PLANT IN SERVICE - OTHER PRODUCTION	\$ 360,783	\$ 340,443	0.943622	\$ 361,892	\$ 341,489	0.943622
5							
6	ELECTRIC PLANT IN SERVICE - TRANSMISSION	\$ 27,217	\$ 24,626	0.904796	\$ 23,004	\$ 20,814	0.904796
7	ELECTRIC PLANT IN SERVICE - TRANSMISSION - GSU's	4,328	4,110	0.949591	6,157	5,846	0.949591
8	TOTAL ELECTRIC PLANT IN SERVICE - TRANSMISSION	\$ 31,545	\$ 28,736	0.910942	\$ 29,160	\$ 26,660	0.910942
9							
10	NON-DEPRECIABLE PROPERTY (LAND)	\$ 18,371	\$ 17,335	0.943622	\$ 18,436	\$ 17,396	0.943622
11							
12	TOTAL PLANT IN SERVICE	\$ 410,699	\$ 386,513	0.941112	\$ 409,488	\$ 385,546	0.941112
13							
14							
15	<u>ACCUMULATED PROVISION FOR DEPRECIATION:</u>						
16							
17	ACCUM PROVISION FOR DEPRECIATION - OTHER PRODUCTION	\$ (6,079)	\$ (5,736)	0.943622	\$ (6,079)	\$ (5,736)	0.943622
18							
19	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION	\$ (272)	\$ (246)	0.904796	\$ (272)	\$ (246)	0.904796
20	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION - GSU	(57)	(54)	0.949591	(57)	(54)	0.949591
21	TOTAL ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION	\$ (329)	\$ (301)	0.912568	\$ (329)	\$ (301)	0.912568
22							
23	TOTAL ACCUMULATED PROVISION FOR DEPRECIATION	\$ (6,408)	\$ (6,037)	0.942026	\$ (6,408)	\$ (6,037)	0.942026
24							
25							
26	ACCUMULATED DEFERRED INCOME TAXES	\$ (17,752)	\$ (16,707)	0.941126	\$ (17,752)	\$ (16,707)	0.941126
27							
28	TOTAL RATE BASE	\$ 386,538	\$ 363,770	0.941096	\$ 385,328	\$ 362,802	0.941096
29							
30							

NOTES:

- (1) Reflects projected rate base included in the Initial SoBRA calculation approved by the Commission in Order No. PSC-20190484, Docket No. 20190001-EI (issued on November 18, 2019).
(2) Reflects rate base included in the initial SoBRA in column 3, except projected plant in service has been replaced with final actual plant in service.

**FLORIDA POWER & LIGHT COMPANY
OKEECHOBEE GBRA FACTOR CALCULATION
REVISED OKEECHOBEE FACTOR**

GBRA FACTOR TRUE-UP CALCULATION

	<u>(\$Million)</u>	<u>Source</u>
(A) Initial 2019 Okeechobee GBRA Revenue Requirement*	\$200.000	See Note
(B) Revised Okeechobee GBRA Project Jurisdictional Annualized Revenue Requirement	\$198.264	Attachment JC-1 as Filed
(C) Change in Jurisdictional Annualized Revenue Requirement	(\$1.736)	Attachment JC-1 as Filed
(D) Total Retail Base Revenues From the Sales of Electricity *	\$6,578.103	See Note
(E) Revised GBRA Factor $[(B) / (D)]$	3.014%	
(F) Initial GBRA Factor *	3.040%	See Note

* As filed in TCC-1, Page 1 of 1; Docket No. 20180001-EI

FLORIDA POWER & LIGHT COMPANY
OKEECHOBEE REVENUE - GBRA PROVISION FOR REFUND CALCULATION

	(1)	(2)	(3)	(4)	(5)
	ACTUALS			REVISED	
	UNBILLED GBRA REV	BILLED GBRA REV	UNBILLED + BILLED GBRA REV	UNBILLED + BILLED GBRA REV	REFUND
Apr-19	940,784	15,469,969	16,410,754	16,268,307	142,447
May-19	1,759,829	16,920,248	18,680,077	18,517,932	162,145
Jun-19	69,782	19,221,341	19,291,123	19,123,674	167,449
Jul-19	253,738	20,070,540	20,324,278	20,147,860	176,417
Aug-19	32,095	19,737,806	19,769,901	19,598,296	171,605
Sep-19	(996,789)	20,227,858	19,231,069	19,064,141	166,928
Oct-19	112,674	18,913,945	19,026,619	18,861,466	165,153
Nov-19	(2,202,352)	17,025,760	14,823,408	14,694,739	128,669
Dec-19	363,873	14,442,340	14,806,213	14,677,693	128,520
Jan-20	(588,144)	14,950,220	14,362,077	14,237,412	124,665
Feb-20	186,853	14,020,313	14,207,166	14,083,846	123,320
Mar-20	1,595,304	14,670,103	16,265,407	16,124,222	141,186
Apr-20	(183,042)	17,101,479	16,918,436	16,771,582	146,854
May-20	699,273	17,264,704	17,963,977	17,808,047	155,929
Jun-20	929,345	18,998,142	19,927,486	19,754,513	172,973
Jul-20	(90,599)	20,931,031	20,840,432	20,659,534	180,897
Aug-20	422,946	21,001,664	21,424,610	21,238,642	185,968
Sep-20	(1,214,537)	20,837,094	19,622,557	19,452,231	170,326
Oct-20	391,407	18,701,274	19,092,681	18,926,954	165,727
Nov-20	(1,656,803)	17,533,792	15,876,989	15,739,175	137,814
Dec-20	(108,288)	14,976,305	14,868,017	14,738,961	129,056
Jan-21	(602,243)	14,848,381	14,246,138	14,122,480	123,658
Feb-21	93,979	14,539,808	14,633,786	14,506,763	127,023
Mar-21	719,388	15,091,261	15,810,648	15,673,410	137,238
Apr-21	271,429	15,989,000	16,260,429	16,119,287	141,142
May-21	737,968	18,092,219	18,830,187	18,666,739	163,448
Jun-21	141,453	18,970,854	19,112,307	18,946,410	165,897
Jul-21	719,045	19,764,683	20,483,727	20,305,926	177,801
Aug-21	(127,945)	20,322,159	20,194,214	20,018,926	175,288
Sep-21	(1,175,969)	19,863,569	18,687,600	18,525,389	162,211
Oct-21	(428,143)	18,003,117	17,574,974	17,422,421	152,553
Nov-21	(894,997)	16,052,566	15,157,569	15,026,000	131,570
Dec-21	69,875	14,906,320	14,976,195	14,846,200	129,995
TOTAL		579,459,863	579,701,052	574,669,177	5,031,875

**FLORIDA POWER & LIGHT COMPANY
GBRA PROVISION FOR REFUND INTEREST**

	<u>REFUND ACCRUAL</u>	<u>CUMULATIVE REFUND</u>	<u>INTEREST RATE</u>	<u>CUM. REFUND WITH INTEREST</u>	<u>MONTHLY INTEREST</u>	<u>CUMULATIVE INTEREST</u>
Apr-19	142,447	142,447	0.0020458	142,593	146	146
May-19	162,145	304,593	0.0020083	305,188	449	595
Jun-19	167,449	472,042	0.0019625	473,400	763	1,358
Jul-19	176,417	648,459	0.0018417	650,851	1,034	2,392
Aug-19	171,605	820,064	0.0017292	823,730	1,274	3,666
Sep-19	166,928	986,992	0.0016750	992,178	1,520	5,186
Oct-19	165,153	1,152,145	0.0015125	1,158,957	1,626	6,811
Nov-19	128,669	1,280,814	0.0013875	1,289,323	1,697	8,509
Dec-19	128,520	1,409,334	0.0013583	1,419,681	1,839	10,347
Jan-20	124,665	1,533,999	0.0013458	1,546,341	1,995	12,342
Feb-20	123,320	1,657,319	0.0013333	1,671,804	2,144	14,486
Mar-20	141,186	1,798,504	0.0015708	1,815,727	2,737	17,223
Apr-20	146,854	1,945,358	0.0009458	1,964,368	1,787	19,010
May-20	155,929	2,101,288	0.0000583	2,120,417	119	19,129
Jun-20	172,973	2,274,261	0.0000875	2,293,583	193	19,322
Jul-20	180,897	2,455,158	0.0001000	2,474,719	238	19,560
Aug-20	185,968	2,641,126	0.0001000	2,660,943	257	19,817
Sep-20	170,326	2,811,453	0.0001000	2,831,544	275	20,092
Oct-20	165,727	2,977,179	0.0000875	2,997,526	255	20,347
Nov-20	137,814	3,114,993	0.0001042	3,135,660	319	20,666
Dec-20	129,056	3,244,050	0.0001000	3,265,036	320	20,986
Jan-21	123,658	3,367,708	0.0000708	3,388,930	236	21,222
Feb-21	127,023	3,494,731	0.0000708	3,516,197	245	21,466
Mar-21	137,238	3,631,969	0.0000833	3,653,734	299	21,765
Apr-21	141,142	3,773,112	0.0000750	3,795,156	279	22,044
May-21	163,448	3,936,560	0.0000458	3,958,782	178	22,222
Jun-21	165,897	4,102,457	0.0000500	4,124,881	202	22,424
Jul-21	177,801	4,280,258	0.0000583	4,302,928	246	22,670
Aug-21	175,288	4,455,546	0.0000583	4,478,473	256	22,926
Sep-21	162,211	4,617,757	0.0000583	4,640,949	266	23,192
Oct-21	152,553	4,770,310	0.0000583	4,793,777	275	23,467
Nov-21	131,570	4,901,879	0.0000583	4,925,630	283	23,751
Dec-21	129,995	5,031,875	0.0000583	5,055,916	291	24,042
TOTAL	<u>5,031,875</u>				<u>24,042</u>	
Total Cumulative Refund with Interest					<u>5,055,916</u>	

**FLORIDA POWER & LIGHT COMPANY
SOBRA FACTOR CALCULATION
REVISED 2019 SOBRA FACTOR**

2019 SOBRA FACTOR TRUE-UP CALCULATION

	<u>(\$Million)</u>	<u>Source</u>
(A) Initial 2019 Project Jurisdictional Annualized Revenue Requirement *	\$51.685	See Note
(B) Revised 2019 Project Jurisdictional Annualized Revenue Requirement	\$51.659	Attachment JC-2 as Filed
(C) Change in Jurisdictional Annualized Revenue Requirement	(\$0.027)	Attachment JC-2 as Filed
(D) Total Retail Base Revenues From the Sales of Electricity *	\$6,501.950	See Note
(E) Revised SoBRA Factor [(B) / (D)]	0.7945%	
(F) Initial SoBRA Factor *	0.7949%	See Note

* As filed in TCC-1, Page 1 of 1; Docket No. 20180001-EI

FLORIDA POWER & LIGHT COMPANY
2019 PROJECT REVENUE - SOBRA PROVISION FOR REFUND CALCULATION

	(1)	(2)	(3)	(4)	(5)
	<u>ACTUALS</u>			<u>REVISED</u>	
	<u>UNBILLED</u>	<u>BILLED</u>	<u>UNBILLED + BILLED</u>	<u>UNBILLED + BILLED</u>	
	<u>SOBRA REV</u>	<u>SOBRA REV</u>	<u>SOBRA REV</u>	<u>SOBRA REV</u>	<u>REFUND</u>
Feb-19	108,457	3,579,442	3,687,899	3,685,981	1,919
Mar-19	59,300	3,829,750	3,889,050	3,887,027	2,023
Apr-19	251,452	4,134,792	4,386,244	4,383,962	2,282
May-19	470,365	4,522,421	4,992,785	4,990,188	2,598
Jun-19	18,651	5,137,454	5,156,105	5,153,422	2,683
Jul-19	67,819	5,364,426	5,432,245	5,429,419	2,826
Aug-19	8,578	5,275,494	5,284,072	5,281,323	2,749
Sep-19	(266,420)	5,406,474	5,140,054	5,137,380	2,674
Oct-19	30,115	5,055,293	5,085,409	5,082,763	2,646
Nov-19	(588,642)	4,550,622	3,961,980	3,959,919	2,061
Dec-19	97,255	3,860,129	3,957,384	3,955,325	2,059
Jan-20	(157,198)	3,995,874	3,838,676	3,836,679	1,997
Feb-20	49,942	3,747,330	3,797,272	3,795,296	1,976
Mar-20	426,391	3,921,005	4,347,396	4,345,134	2,262
Apr-20	(48,923)	4,570,860	4,521,936	4,519,584	2,353
May-20	186,901	4,614,486	4,801,387	4,798,889	2,498
Jun-20	248,394	5,077,797	5,326,191	5,323,420	2,771
Jul-20	(24,215)	5,594,417	5,570,202	5,567,304	2,898
Aug-20	113,044	5,613,296	5,726,340	5,723,361	2,979
Sep-20	(324,620)	5,569,310	5,244,690	5,241,962	2,729
Oct-20	104,615	4,998,451	5,103,066	5,100,411	2,655
Nov-20	(442,828)	4,686,408	4,243,580	4,241,372	2,208
Dec-20	(28,943)	4,002,846	3,973,903	3,971,836	2,067
Jan-21	(160,967)	3,968,655	3,807,688	3,805,707	1,981
Feb-21	25,118	3,886,180	3,911,298	3,909,263	2,035
Mar-21	192,277	4,033,571	4,225,848	4,223,650	2,199
Apr-21	72,547	4,273,518	4,346,065	4,343,804	2,261
May-21	197,243	4,835,664	5,032,907	5,030,288	2,618
Jun-21	37,807	5,070,504	5,108,311	5,105,654	2,658
Jul-21	192,185	5,282,677	5,474,863	5,472,014	2,848
Aug-21	(34,197)	5,431,679	5,397,482	5,394,674	2,808
Sep-21	(314,311)	5,309,107	4,994,796	4,992,198	2,599
Oct-21	(114,434)	4,811,848	4,697,415	4,694,971	2,444
Nov-21	(239,214)	4,290,508	4,051,294	4,049,187	2,108
Dec-21	18,676	3,984,141	4,002,817	4,000,734	2,083
TOTAL		<u>162,286,430</u>	<u>162,518,652</u>	<u>162,434,100</u>	<u>84,552</u>

**FLORIDA POWER & LIGHT COMPANY
SOBRA PROVISION FOR REFUND INTEREST**

	<u>REFUND ACCRUAL</u>	<u>CUMULATIVE REFUND</u>	<u>INTEREST RATE</u>	<u>CUM. REFUND WITH INTEREST</u>	<u>MONTHLY INTEREST</u>	<u>CUMULATIVE INTEREST</u>
Feb-19	1,919	1,919	0.0020125	1,921	2	2
Mar-19	2,023	3,942	0.0020375	3,950	6	8
Apr-19	2,282	6,224	0.0020458	6,242	10	18
May-19	2,598	8,822	0.0020083	8,855	15	33
Jun-19	2,683	11,504	0.0019625	11,557	20	53
Jul-19	2,826	14,330	0.0018417	14,408	24	77
Aug-19	2,749	17,079	0.0017292	17,184	27	105
Sep-19	2,674	19,753	0.0016750	19,889	31	136
Oct-19	2,646	22,399	0.0015125	22,567	32	168
Nov-19	2,061	24,460	0.0013875	24,661	33	201
Dec-19	2,059	26,519	0.0013583	26,755	35	235
Jan-20	1,997	28,516	0.0013458	28,789	37	273
Feb-20	1,976	30,492	0.0013333	30,804	40	312
Mar-20	2,262	32,754	0.0015708	33,116	50	363
Apr-20	2,353	35,106	0.0009458	35,501	32	395
May-20	2,498	37,604	0.0000583	38,002	2	397
Jun-20	2,771	40,375	0.0000875	40,776	3	401
Jul-20	2,898	43,273	0.0001000	43,678	4	405
Aug-20	2,979	46,252	0.0001000	46,662	5	409
Sep-20	2,729	48,981	0.0001000	49,395	5	414
Oct-20	2,655	51,636	0.0000875	52,055	4	419
Nov-20	2,208	53,844	0.0001042	54,268	6	424
Dec-20	2,067	55,911	0.0001000	56,341	6	430
Jan-21	1,981	57,892	0.0000708	58,326	4	434
Feb-21	2,035	59,927	0.0000708	60,365	4	438
Mar-21	2,199	62,126	0.0000833	62,569	5	443
Apr-21	2,261	64,387	0.0000750	64,835	5	448
May-21	2,618	67,005	0.0000458	67,456	3	451
Jun-21	2,658	69,663	0.0000500	70,117	3	454
Jul-21	2,848	72,511	0.0000583	72,970	4	458
Aug-21	2,808	75,319	0.0000583	75,782	4	463
Sep-21	2,599	77,918	0.0000583	78,385	4	467
Oct-21	2,444	80,362	0.0000583	80,834	5	472
Nov-21	2,108	82,469	0.0000583	82,946	5	477
Dec-21	2,083	84,552	0.0000583	85,034	5	482
TOTAL	<u>84,552</u>				<u>482</u>	
Total Cumulative Refund with Interest					<u>85,034</u>	

**FLORIDA POWER & LIGHT COMPANY
SOBRA FACTOR CALCULATION
REVISED 2020 SOBRA FACTOR**

2020 SOBRA FACTOR TRUE-UP CALCULATION

	<u>(\$Million)</u>	<u>Source</u>
(A) Initial 2020 Project Jurisdictional Annualized Revenue Requirement *	\$50.491	See Note
(B) Revised 2020 Project Jurisdictional Annualized Revenue Requirement	\$50.384	Attachment JC-3 as Filed
(C) Change in Jurisdictional Annualized Revenue Requirement	(\$0.107)	Attachment JC-3 as Filed
(D) Total Retail Base Revenues From the Sales of Electricity *	\$6,896.706	See Note
(E) Revised SoBRA Factor [(B) / (D)]	0.731%	
(F) Initial SoBRA Factor *	0.732%	See Note

* As filed in EJA-1, Page 1 of 1; Docket No. 20190001-EI

FLORIDA POWER & LIGHT COMPANY
2020 PROJECT REVENUE - SOBRA PROVISION FOR REFUND CALCULATION

	(1)	(2)	(3)	(4)	(5)
	ACTUALS			REVISED	
	UNBILLED	BILLED	UNBILLED + BILLED	UNBILLED + BILLED	
	<u>SOBRA REV</u>	<u>SOBRA REV</u>	<u>SOBRA REV</u>	<u>SOBRA REV</u>	<u>REFUND</u>
May-20	172,214	4,251,879	4,424,093	4,418,050	6,044
Jun-20	228,875	4,678,783	4,907,658	4,900,954	6,704
Jul-20	(22,312)	5,154,807	5,132,495	5,125,483	7,012
Aug-20	104,161	5,172,202	5,276,364	5,269,156	7,208
Sep-20	(299,111)	5,131,673	4,832,562	4,825,960	6,602
Oct-20	96,394	4,605,672	4,702,066	4,695,642	6,424
Nov-20	(408,031)	4,318,149	3,910,119	3,904,777	5,342
Dec-20	(26,669)	3,688,302	3,661,633	3,656,631	5,002
Jan-21	(148,318)	3,656,798	3,508,480	3,503,687	4,793
Feb-21	23,145	3,580,803	3,603,948	3,599,024	4,923
Mar-21	177,168	3,716,613	3,893,781	3,888,461	5,319
Apr-21	66,846	3,937,704	4,004,551	3,999,080	5,471
May-21	181,744	4,455,676	4,637,420	4,631,085	6,335
Jun-21	34,837	4,672,063	4,706,899	4,700,469	6,430
Jul-21	177,083	4,867,564	5,044,647	5,037,755	6,892
Aug-21	(31,510)	5,004,857	4,973,347	4,966,553	6,794
Sep-21	(289,613)	4,891,917	4,602,304	4,596,017	6,287
Oct-21	(105,441)	4,433,733	4,328,291	4,322,378	5,913
Nov-21	(220,416)	3,953,359	3,732,943	3,727,843	5,100
Dec-21	17,209	3,671,066	3,688,275	3,683,236	5,039
TOTAL		87,843,621	87,571,876	87,452,242	119,634

**FLORIDA POWER & LIGHT COMPANY
SOBRA PROVISION FOR REFUND INTEREST**

	<u>REFUND ACCRUAL</u>	<u>CUMULATIVE REFUND</u>	<u>INTEREST RATE</u>	<u>CUM. REFUND WITH INTEREST</u>	<u>MONTHLY INTEREST</u>	<u>CUMULATIVE INTEREST</u>
May-20	6,044	6,044	0.0000583	6,044	0	0
Jun-20	6,704	12,748	0.0000875	12,749	1	1
Jul-20	7,012	19,760	0.0001000	19,763	2	3
Aug-20	7,208	26,968	0.0001000	26,973	2	5
Sep-20	6,602	33,570	0.0001000	33,578	3	8
Oct-20	6,424	39,993	0.0000875	40,005	3	11
Nov-20	5,342	45,335	0.0001042	45,351	4	16
Dec-20	5,002	50,337	0.0001000	50,358	5	20
Jan-21	4,793	55,130	0.0000708	55,155	4	24
Feb-21	4,923	60,054	0.0000708	60,082	4	28
Mar-21	5,319	65,373	0.0000833	65,407	5	33
Apr-21	5,471	70,844	0.0000750	70,883	5	39
May-21	6,335	77,179	0.0000458	77,221	3	42
Jun-21	6,430	83,609	0.0000500	83,655	4	46
Jul-21	6,892	90,501	0.0000583	90,552	5	51
Aug-21	6,794	97,295	0.0000583	97,352	5	57
Sep-21	6,287	103,582	0.0000583	103,645	6	62
Oct-21	5,913	109,495	0.0000583	109,564	6	69
Nov-21	5,100	114,595	0.0000583	114,670	7	75
Dec-21	5,039	119,634	0.0000583	119,716	7	82
TOTAL	<u>119,634</u>				<u>82</u>	
Total Cumulative Refund with Interest					<u>119,716</u>	

Schedule A

FLORIDA PUBLIC UTILITIES
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2020 THROUGH DECEMBER 2020

CONSOLIDATED ELECTRIC DIVISION

1 JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	\$ 38,386,129
2 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	<u>44,537,568</u>
3 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD	6,151,439
4 ADJUSTMENTS* (see below)	(878,874)
5 INTEREST	(19,593)
6 TRUE-UP COLLECTED	1,934,450
7 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/19)	<u>(3,952,348)</u>
8 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 3 + LINE4 + LINE5 + LINE6 + LINE7)	3,235,074
9 PROJECTED OVER-RECOVERY PER PROJECTION FILED 7/27/20	<u>297,168</u>
10 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 8 - LINE 9)	<u>\$ 2,937,906</u>

* Revenue Refund True-Up Adjustment	\$ (1,934,450)
Over-collected Base revenues - Hurricane Michael Settlement	975,259
State Income Tax reserve - 2019	27,870
State Income Tax reserve - 2020	<u>52,447</u>
	\$ (878,874)

FLORIDA PUBLIC UTILITIES COMPANY

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

Schedule E-1b

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED
(EXCLUDES LINE LOSS, EXCLUDES TAXES)

CONSOLIDATED

Revised 10_22_2020

	ACTUAL Jan 2020	ACTUAL Feb 2020	ACTUAL Mar 2020	ACTUAL Apr 2020	ACTUAL May 2020	ACTUAL Jun 2020	Estimated Jul 2020	Estimated Aug 2020	Estimated Sep 2020	Estimated Oct 2020	Estimated Nov 2020	Estimated Dec 2020	Total
Total System Sales - KWH	46,124,472	43,763,223	40,566,336	42,455,602	43,068,192	51,431,735	57,013,028	56,620,476	56,396,478	55,663,197	47,633,732	45,974,398	586,710,869
West-Rock Purchases - KWH	1,020,000	1,150,000	390,000	240,000	360,000	420,000	700,000	400,000	700,000	900,000	500,000	700,000	7,480,000
Rayonier Purchases - KWH - On Peak	40,088	68,692	96,733	55,617	2,478	22,915	310,500	310,500	310,500	310,500	310,500	310,500	2,149,523
Rayonier Purchases - KWH - Off Peak	244,082	162,561	140,260	139,799	144,161	127,811	589,500	589,500	589,500	589,500	589,500	589,500	4,495,674
Eight Flags Purchases - KWH - KWH	15,182,978	13,530,427	15,396,795	14,740,660	14,548,725	12,919,968	12,500,000	12,800,000	12,400,000	15,500,000	15,200,000	15,800,000	170,519,553
FPL Purchases - KWH	11,656,613	8,816,904	5,270,960	7,497,233	14,634,407	20,624,092	21,118,482	20,717,305	20,593,111	15,627,836	10,457,307	9,265,073	166,279,323
Gulf Purchases - KWH	23,471,161	21,007,047	21,513,838	19,820,726	23,913,356	28,150,827	24,645,198	24,634,194	24,623,191	25,518,521	22,588,112	21,608,046	281,864,216
Generation Demand - KW - FPL	59,604	52,531	33,091	51,949	54,052	89,465	66,735	70,199	57,463	50,433	49,192	47,580	681,193
Generation Demand - KW - Gulf	64,609	55,246	45,611	48,506	51,498	61,590	65,000	64,400	61,400	58,500	49,200	59,500	685,060
Transmission Demand - KW - FPL	59,978	63,067	42,962	48,146	49,997	92,146	55,000	58,400	45,900	39,000	36,800	36,200	627,596
Transmission Demand - KW - Southern	55,955	56,072	56,297	57,002	56,000	56,090	55,000	55,000	55,000	55,000	55,000	55,000	667,416
Purchased Power Rates:													
West Rock Fuel Costs - \$/KWH	0.03224	0.02446	(0.00053)	0.01354	0.02761	0.02587	0.03648	0.03648	0.03648	0.03648	0.03648	0.03648	0.03648
Rayonier Energy Charge - On Peak - \$/KWH	0.03491	0.03491	0.03491	0.02368	0.02754	0.02754	0.04826	0.04826	0.04826	0.04826	0.04826	0.04826	0.04826
Rayonier Energy Charge - Off Peak - \$/KWH	0.03248	0.03248	0.03248	0.02078	0.02383	0.02383	0.03898	0.03898	0.03898	0.03898	0.03898	0.03898	0.03898
Eight Flags Charge - \$/KWH	0.07438	0.07095	0.06959	0.06780	0.06886	0.07147	0.08473	0.08473	0.08473	0.08473	0.08473	0.08473	0.08473
Base Fuel Costs - \$/KWH - FPL	0.02629	0.01918	0.01005	0.01517	0.02774	0.02624	0.03037	0.03026	0.03060	0.03095	0.02947	0.02481	0.02481
Base Fuel Costs - \$/KWH - GULF	0.01946	0.01814	0.01701	0.01649	0.01763	0.01800	0.02517	0.02517	0.02586	0.02909	0.02941	0.02538	0.02538
Energy Charge - \$/KWH - FPL	0.00661	0.00794	0.01248	0.00869	0.00549	0.00465	0.00453	0.00459	0.00449	0.00491	0.00608	0.00776	0.00776
Demand and Non-Fuel:													
Demand Charge - \$/KW - FPL	6.53	6.70	7.56	6.72	6.66	6.10	6.39	6.34	6.58	6.76	6.83	6.85	
Demand Charge - \$/KW - Gulf	7.86	8.31	8.95	8.73	8.53	5.05	7.85	7.87	8.00	8.14	8.68	8.09	
Distribution Facility Charge	1.55234	1.54954	1.54117	1.52155	1.54639	1.54969	2.60415	2.60415	2.60415	2.60415	2.60415	2.60415	
Transmission Charge \$/KW - FPL	3.13960	3.61204	4.91039	3.15276	3.49933	3.16289	2.43455	2.43454	2.43453	2.43454	2.43454	2.43453	
Transmission Charge \$/KW - Southern	3.01532	3.01632	3.01631	3.01635	3.06438	3.31430	2.17647	2.13805	1.94602	1.76038	1.16505	1.82440	
Purchased Power Costs:													
West-Rock Fuel Costs	32,882	28,131	(207)	3,249	9,940	10,867	25,536	14,592	25,536	32,832	18,240	25,536	227,134
Rayonier Standby Costs	9,327	7,678	7,932	4,223	3,504	3,677	37,964	37,964	37,964	37,964	37,964	37,964	264,125
Eight Flags	1,129,372	959,932	1,071,505	999,485	1,001,850	923,410	1,059,125	1,084,544	1,050,652	1,313,315	1,287,896	1,338,734	13,219,820
Gulf Base Fuel Costs	456,822	380,975	365,867	326,777	421,601	506,835	620,408	620,010	636,813	742,325	675,284	548,436	6,302,153
FPL Base Fuel Costs	306,404	169,105	52,963	113,741	405,894	541,116	641,456	626,946	630,222	483,658	308,190	229,836	4,509,531
FPL Fuel Adjustment	77,060	70,011	65,787	65,124	80,301	95,976	95,605	95,102	92,419	76,742	63,549	71,858	949,534
Subtotal Fuel Costs	2,011,867	1,615,832	1,563,847	1,512,599	1,923,090	2,081,881	2,480,094	2,479,158	2,473,606	2,686,836	2,391,123	2,252,364	26,472,296
Demand Capacity Charge	897,368	811,080	658,436	772,114	799,388	856,900	936,857	951,893	869,281	817,148	756,556	807,421	9,934,442
Distr. Fac. Charge	86,861	86,886	86,763	86,731	86,598	86,922	143,228	143,228	143,228	143,228	143,228	143,228	1,380,129
Customer Charges	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	48,000
Transmission Charge	357,085	396,932	380,769	323,731	346,561	477,347	253,606	259,770	218,776	191,768	153,669	188,472	3,548,485
Subtotal Demand & Non-Fuel Costs	1,345,314	1,298,898	1,129,968	1,186,576	1,236,547	1,425,169	1,337,691	1,358,891	1,235,285	1,156,144	1,057,453	1,143,121	14,911,056
Total System Purchased Power Costs	3,357,181	2,914,730	2,693,815	2,699,175	3,159,636	3,507,050	3,817,785	3,838,049	3,708,891	3,842,980	3,448,576	3,395,485	40,383,352
Less Direct Billing To GSLD1 Class:													
Demand	105,944	81,729	(289,768)	17,029	28,724	(12,805)	30,407	30,407	30,407	30,407	30,407	30,407	113,294
Commodity	(1,090)	3,471	10,762	8,175	12,695	23,426	68,200	51,186	50,876	55,101	60,536	77,043	415,481
Net Purchased Power Costs	3,252,327	2,829,530	2,972,821	2,678,970	3,118,217	3,496,429	3,719,178	3,756,456	3,627,508	3,757,472	3,357,633	3,288,035	39,854,577
Special Costs*	1,960	25,242	995	6,460	14,922	12,649	8,925	8,925	9,650	8,925	8,925	10,150	117,726
Total Costs and Charges	3,254,287	2,854,772	2,973,816	2,685,430	3,133,139	3,509,078	3,728,103	3,765,381	3,637,158	3,766,397	3,366,558	3,298,185	39,972,304
Sales Revenues - Fuel Adjustment Revenues:													
RS< 0.07454	1,300,141	1,292,120	1,223,294	1,224,127	1,244,061	1,400,952	1,386,978	1,388,170	1,388,692	1,400,137	1,224,059	1,271,922	15,744,653
RS> 0.08703	472,335	429,438	295,532	380,380	414,284	673,318	707,740	704,211	650,767	598,381	320,107	380,711	6,027,204
GS 0.07530	302,113	302,592	273,990	285,837	277,295	340,292	387,389	387,642	388,148	373,989	314,547	288,516	3,922,350
GSD 0.07223	860,359	817,751	792,294	807,527	799,455	953,693	1,129,333	1,151,622	1,142,375	1,104,500	1,067,138	899,163	11,525,210
GSLD 0.07004	429,065	381,274	381,145	405,635	428,719	432,819	530,930	506,688	541,795	575,011	491,924	451,451	5,556,456
LS 0.05617	35,167	35,082	34,985	34,829	34,794	34,789	35,583	35,369	35,466	34,606	34,781	34,855	420,388
Unbilled Fuel Revenues	(531,323)	206,031	(44,628)	(31,070)	23,255	361,616	0	0	0	0	0	0	(16,119)
Total Fuel Revenues (Excl. GSD1)	2,867,857	3,464,288	2,956,612	3,107,265	3,221,863	4,197,479	4,177,953	4,173,702	4,147,323	4,086,624	3,452,556	3,326,618	43,180,139
GSD1 Fuel - 17197	104,854	85,200	(279,006)	20,204	41,419	10,621	98,607	81,593	81,383	85,508	90,943	107,450	528,775
Non-Fuel Revenues	2,283,185	2,175,757	1,687,923	2,020,524	2,125,910	2,429,393	2,992,982	2,811,401	2,798,088	1,834,509	1,861,988	2,593,999	27,615,661
Total Sales Revenue	5,255,896	5,225,245	4,365,529	5,147,993	5,389,192	6,637,492	7,269,543	7,066,696	7,026,794	6,006,642	5,405,487	6,028,067	71,324,575
KWH Sales:													
RS<	17,440,088	17,336,516	16,415,648	16,423,857	16,691,757	18,797,031	18,607,171	18,623,150	18,630,156	18,783,698	16,421,502	17,063,615	211,234,188
RS>	5,426,957	4,934,587	3,393,219	4,370,806	4,760,390	7,736,857	8,132,138	8,091,588	7,477,501	6,875,568	3,678,128	4,374,478	69,252,218
GS	4,016,057	4,018,710	3,638,850	3,796,191	3,682,743	4,519,400	5,144,612	5,147,972	5,154,691	4,966,650	4,177,253	3,831,552	52,094,681
GSD	11,911,722	11,321,800	10,969,350	11,180,245	11,068,489	13,203,918	15,635,233	15,943,819	15,815,799	15,291,426	14,774,164	12,448,607	159,564,573
GSLD	6,128,433	5,443,691	5,441,849	5,791,512	6,121,096	6,179,635	7,580,380	7,234,267	7,735,507	8,209,757	7,023,473	6,445,616	79,335,216
GSD1	574,000	82,000	82,000	272,000	124,000	374,000	1,280,000	950,000	950,000	920,000	940,000	1,190,000	7,738,000
LS	627,215	625,919	625,420	620,991	619,717	620,894	633,494	629,680	632,823	616,097	619,212	620,531	7,491,993
Total KWH Sales	46,124,472	43,763,223	40,566,336	42,455,602	43,068,192	51,431,735	57,013,028	56,620,476	56,396,478	55,663,197	47,633,732	45,974,398	5

FLORIDA PUBLIC UTILITIES COMPANY

Schedule C1

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

BASED ON TWELVE MONTHS ACTUAL

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

2020													
	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	Total
Total System Sales - KWH	46,124,472	43,763,223	40,566,336	42,455,602	43,068,192	51,431,735	66,096,167	65,655,059	59,753,786	49,596,356	47,439,578	46,010,509	601,961,015
WEST-ROCK Purchases - KWH	1,020,000	1,150,000	390,000	240,000	360,000	420,000	190,000	350,000	590,000	320,000	530,000	440,000	6,000,000
Rayonier Purchases - KWH - On Peak	40,088	68,692	96,733	55,617	2,478	22,915	30,081	21,592	54,109	73,651	147,221	74,882	688,059
Rayonier Purchases - KWH - Off Peak	244,082	162,561	140,260	139,799	144,161	127,811	71,693	107,477	205,575	413,363	362,757	212,799	2,332,338
Eight Flags Purchases-KWH	15,182,978	13,530,427	15,396,795	14,740,660	14,548,725	12,919,968	14,335,732	13,070,334	14,171,327	14,545,285	13,899,225	14,637,336	170,978,792
Gulf Purchases - KWH - BLOCK	21,199,735	19,722,200	20,352,689	18,955,580	20,918,000	21,715,270	22,815,423	22,798,255	21,402,634	21,074,508	19,923,006	22,259,989	253,137,289
Gulf Purchases - KWH - LOAD	2,271,426	1,284,847	1,161,149	865,146	2,995,356	6,435,557	8,301,585	8,290,898	4,986,660	2,980,715	946,425	4,154,198	44,673,962
FPL Purchases - KWH - BLOCK	7,190,664	7,059,043	6,564,834	6,918,263	6,316,387	8,241,871	9,715,272	10,356,679	10,034,035	9,173,237	9,792,147	6,784,042	98,146,474
FPL Purchases - KWH - LOAD	4,465,949	1,757,861	(1,293,874)	578,970	8,318,020	12,382,221	13,996,017	13,921,101	7,144,591	1,945,793	4,380,228	6,911,432	74,508,309
FPL Billing Demand - KW - BLOCK	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	168,000
FPL Billing Demand - KW - LOAD	45,604	38,531	19,091	37,849	40,052	75,465	52,035	60,542	84,215	32,705	34,813	41,109	562,011
FPL BULK Transmission Demand - KW	59,978	63,067	42,962	48,146	49,997	92,146	49,567	79,813	66,086	47,885	(9,021)	102,115	692,741
Gulf Demand - KW - BLOCK	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	372,000
Gulf . Demand-KW - LOAD	33,609	24,246	14,611	17,506	20,498	30,590	30,886	32,799	30,504	20,822	16,156	34,011	306,238
Gulf Transmission Demand - KW- Block / Load	55,955	56,072	56,297	57,002	56,000	56,090	54,631	54,395	55,514	53,814	53,678	52,773	662,221
Purchased Power Costs: Fuel Costs	1,934,807	1,545,820	1,498,061	1,447,473	1,842,789	1,985,905	2,162,611	2,234,572	2,155,517	1,808,138	2,031,076	2,371,563	23,018,332
Demand & Non-Fuel Costs	1,422,374	1,368,909	1,195,755	1,251,700	1,316,848	1,521,145	1,587,102	1,652,339	1,751,266	1,370,720	1,105,425	34,482	15,578,065
Total System Purchased Power Costs	3,357,181	2,914,729	2,693,816	2,699,173	3,159,637	3,507,050	3,749,713	3,886,911	3,906,783	3,178,859	3,136,501	2,406,045	38,596,398
Less Direct Billing To GSLD1 Class: Demand	105,944	81,729	(289,768)	17,029	28,724	(12,805)	164,667	(16,701)	17,481	89,580	(10,879)	46,642	221,642
(these 2 amounts (Demand and comodity) should e Commodity)	(1,090)	3,471	10,762	3,175	12,695	23,426	7,740	16,158	(2,557)	9,221	(2,995)	19,519	99,525
Net Purchased Power Costs	3,252,327	2,829,529	2,972,822	2,678,969	3,118,218	3,496,430	3,577,306	3,887,455	3,891,859	3,080,057	3,150,375	2,339,883	38,275,230
Special Costs	1,960	25,243	994	6,460	14,921	12,649	6,974	6,681	12,863	10,405	6,744	5,005	110,900
Net Purchased Power and Other Fuel Costs	3,254,287	2,854,772	2,973,816	2,685,430	3,133,139	3,509,079	3,584,280	3,894,136	3,904,722	3,090,463	3,157,119	2,344,888	38,386,129
Sales Revenues: Fuel Adjustment Revenues	3,399,181	3,258,257	3,001,240	3,138,335	3,198,608	3,835,863	4,971,207	4,966,170	4,477,199	3,702,024	3,506,599	3,443,013	44,897,696
Unbilled Fuel Revenues	(531,324)	206,031	(44,628)	(31,070)	23,255	361,616	78,684	55,939	(205,952)	(94,077)	(142,809)	(35,794)	(360,128)
Total Fuel Revenues (Excl. GSLD1)	2,867,857	3,464,288	2,956,612	3,107,265	3,221,863	4,197,479	5,049,891	5,022,109	4,271,247	3,607,948	3,363,790	3,407,220	44,537,568
GSLD1 Fuel Revenues	104,854	85,200	(279,006)	20,204	41,419	10,621	172,407	(543)	14,924	98,801	(13,874)	66,161	321,167
Non-Fuel Revenues	2,283,185	2,175,757	1,687,923	2,020,524	2,125,910	2,429,393	2,902,289	2,878,390	10,958,129	3,275,892	3,079,675	2,593,999	38,411,066
Total Sales Revenue	5,255,896	5,725,245	4,365,529	5,147,993	5,389,192	6,637,492	8,124,587	7,899,956	15,244,300	6,982,641	6,429,590	6,067,380	83,269,801
True-up Calculation (Excl. GSLD1):													
Fuel Revenues	2,867,857	3,464,288	2,956,612	3,107,265	3,221,863	4,197,479	5,049,891	5,022,109	4,271,247	3,607,948	3,363,790	3,407,220	44,537,568
True-up Provision - collect/(refund)	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	1,934,450
Fuel Revenue	2,706,653	3,303,084	2,795,408	2,946,061	3,060,658	4,036,274	4,888,687	4,860,905	4,110,043	3,446,744	3,202,586	3,246,016	42,603,118
Net Purchased Power and Other Fuel Costs	3,254,287	2,854,772	2,973,816	2,685,430	3,133,139	3,509,079	3,584,280	3,894,136	3,904,722	3,090,463	3,157,119	2,344,888	38,386,129
True-up Provision for the Period	(547,634)	448,312	(178,409)	260,631	(72,480)	527,196	1,304,407	966,770	205,321	356,281	45,467	901,127	4,216,989
Interest Provision for the Period	(5,493)	(5,219)	(5,342)	(3,154)	(455)	(256)	(152)	(40)	48	118	151	201	(19,593)
Beginning of Period True-up and Interest Provision	(3,952,348)	(4,344,271)	(3,739,974)	(3,762,520)	(3,343,838)	(3,255,569)	(2,567,425)	(1,101,966)	25,968	1,418,752	1,913,273	2,120,095	(3,952,348)
True-up Collected or (Refunded)	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	1,934,450
Overcollected Interin Rates-Hurricane Michael									1,026,212	(23,082)		52,447	1,055,577
End of Period, Net True-up and Int. Prov.	(4,344,271)	(3,739,974)	(3,762,520)	(3,343,838)	(3,255,569)	(2,567,425)	(1,101,966)	25,968	1,418,752	1,913,273	2,120,095	3,235,074	3,235,074
Beginning True-up Amount	(3,952,348)	(4,344,271)	(3,739,974)	(3,762,520)	(3,343,838)	(3,255,569)	(2,567,425)	(1,101,966)	25,968	1,418,752	1,913,273	2,120,095	
Ending True-up Amount Before Interest	(4,338,778)	(3,734,755)	(3,757,178)	(3,340,684)	(3,255,114)	(2,567,169)	(1,101,814)	26,008	1,418,704	1,913,155	2,119,944	3,234,873	
Total Beginning and Ending True-up	(8,291,126)	(8,079,026)	(7,497,152)	(7,103,204)	(6,598,953)	(5,822,738)	(3,669,239)	(1,075,958)	1,444,672	3,331,908	4,033,217	5,354,968	
Average True-up Amount	(4,145,563)	(4,039,513)	(3,748,576)	(3,551,602)	(3,299,476)	(2,911,369)	(1,834,619)	(537,979)	722,336	1,665,954	2,016,609	2,677,484	
Average Annual Interest Rate	1.5900%	1.5500%	1.7100%	1.0650%	0.1650%	0.1050%	0.1000%	0.0900%	0.0800%	0.0850%	0.0900%	0.0900%	
Interest Provision	(5,493)	(5,219)	(5,342)	(3,154)	(455)	(256)	(152)	(40)	48	118	151	201	
													10% Rule Interest Provision: 8.38%

10% Rule Interest Provision: 8.38%
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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2021 - DECEMBER 2021
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Florida Division -CONSOLIDATED

Over-recovery of purchased power costs for the period
January 2021 - December 2021. (See Schedule E1-B, Calculation
of Estimated Purchased Power Costs and Calculation of True-
Up and Interest Provision for the Twelve Month Period ended
December 2021.)(Estimated)

\$ (2,257,470)

Schedule E-1b

(EXCLUDES LINE LOSS, EXCLUDES TAXES)

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Florida Public Utilities Compar
(CDY-2)
Page 2 of 3

* Includes: Consulting fees, Legal fees and Taxes on Company Use

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED FLORIDA DIVISIONS
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2021 - DECEMBER 2021

0

	DOLLARS				MWH				CENTS/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2 Nuclear Fuel Disposal Cost (A13)												
3 Coal Car Investment												
4 Adjustments to Fuel Cost (A2, Page 1)												
5 TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	15,242,211	13,359,070	1,883,141	14.1%	483,934	468,492	15,442	3.3%	3.14965	2.85150	0.29815	10.5%
7 Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8 Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9 Energy Cost of Sched E Economy Purch (A9)												
10 Demand and Non Fuel Cost of Purchased Power (A9)	14,970,711	16,141,377	(1,170,666)	-7.3%	483,934	468,492	15,442	3.3%	3.09354	3.44539	(0.35185)	-10.2%
11 Energy Payments to Qualifying Facilities (A8a)	14,812,491	14,686,523	125,968	0.9%	186,697	196,205	(9,508)	-4.9%	7.93397	7.48529	0.44868	6.0%
12 TOTAL COST OF PURCHASED POWER	45,025,412	44,186,970	838,442	1.9%	670,631	664,697	5,934	0.9%	6.71389	6.64769	0.06620	1.0%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					670,631	664,697	5,934	0.9%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)	185,717	221,000	(35,283)	-16.0%								
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	185,717	221,000	(35,283)	-16.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19 NET INADVERTENT INTERCHANGE (A10)												
20 TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	45,211,130	44,407,970	803,160	1.8%	670,631	664,697	5,934	0.9%	6.74158	6.68093	0.06065	0.9%
21 Net Unbilled Sales (A4)	0 *	0 *	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
22 Company Use (A4)	36,067 *	33,939 *	2,128	6.3%	535	508	27	5.3%	0.00573	0.00567	0.00006	1.1%
23 T & D Losses (A4)	2,709,643 *	4,373,537 *	(1,663,894)	-38.0%	40,193	65,463	(25,270)	-38.6%	0.43017	0.73047	(0.30030)	-41.1%
24 SYSTEM KWH SALES	45,211,130	44,407,970	803,160	1.8%	629,903	598,726	31,177	5.2%	7.17748	7.41707	(0.23959)	-3.2%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	45,211,130	44,407,970	803,160	1.8%	629,903	598,726	31,177	5.2%	7.17748	7.41707	(0.23959)	-3.2%
26a Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27 Jurisdictional KWH Sales Adjusted for Line Losses	45,211,130	44,407,970	803,160	1.8%	629,903	598,726	31,177	5.2%	7.17748	7.41707	(0.23959)	-3.2%
28 GPIF**												
29 TRUE-UP**	(297,168)	(297,168)	0	0.0%	629,903	598,726	31,177	5.2%	(0.04718)	(0.04963)	0.00245	-4.9%
30 TOTAL JURISDICTIONAL FUEL COST	44,913,962	44,110,802	803,160	1.8%	629,903	598,726	31,177	5.2%	7.13030	7.36744	(0.23714)	-3.2%
31 Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									7.13543	7.37274	(0.23731)	-3.2%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.135	7.373	(0.238)	-3.2%

*Included for Informational Purposes Only

**Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
(CDY-2)
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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

FLORIDA DIVISION-CONSOLIDATED

	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
1 Fuel Cost of System Net Generation (E3)			
2 Nuclear Fuel Disposal Costs (E2)			
3 Coal Car Investment			
4 Adjustments to Fuel Cost			
5 TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0	0	0.00000
6 Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	14,112,170	509,609	2.76922
7 Energy Cost of Sched C & X Econ Purch (Broker) (E9)			
8 Energy Cost of Other Econ Purch (Non-Broker) (E9)			
9 Energy Cost of Sched E Economy Purch (E9)			
10 Demand & Non Fuel Cost of Purch Power (E2)	18,006,207	509,609	3.53334
10a Demand Costs of Purchased Power	15,949,684 *		
10b Non-fuel Energy & Customer Costs of Purchased Power	2,056,523 *		
11 Energy Payments to Qualifying Facilities (E8a)	16,588,818	180,913	9.16950
12 TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	48,707,195	690,522	7.05368
13 TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	48,707,195	690,522	7.05368
14 Fuel Cost of Economy Sales (E6)			
15 Gain on Economy Sales (E6)			
16 Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)			
17 Fuel Cost of Other Power Sales			
18 TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19 Net Inadvertent Interchange			
20 TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	48,707,195	690,522	7.05368
21 Net Unbilled Sales	0 *	0	0.00000
22 Company Use	35,833 *	508	0.00545
23 T & D Losses	2,283,518 *	32,373	0.34723
24 SYSTEM MWH SALES	48,707,195	657,641	7.40635
25 Wholesale MWH Sales			
26 Jurisdictional MWH Sales	48,707,195	657,641	7.40635
26a Jurisdictional Loss Multiplier	1.00000	1.00000	
27 Jurisdictional MWH Sales Adjusted for Line Losses	48,707,195	657,641	7.40635
27a GSLD1 MWH Sales		23,648	
27b Other Classes MWH Sales		633,993	
27c GSLD1 CP KW		51,500 *	
28 Projected Unbilled Revenues	0	633,993	0.00000
29 GPIF **			
30 TRUE-UP (OVER) UNDER RECOVERY **	(2,257,470)	633,993	-0.35607
31 TOTAL JURISDICTIONAL FUEL COST	46,449,725	633,993	7.32654
31a Demand Purchased Power Costs (Line 10a)	15,949,684 *		
31b Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	32,757,511 *		
31c True up Over/Under Recovery (Line 29)	(2,257,470) *		
31d Unbilled Revenues	0		

* For Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 1 OF 8

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

FLORIDA DIVISION-CONSOLIDATED

	(a)	(b)	(c)
	DOLLARS	MWH	CENTS/KWH
APPORTIONMENT OF DEMAND COSTS			
31 Total Demand Costs (Line 31a)	15,949,684		
32 GSLD1 Portion of Demand Costs (Line 31a) Including Line Losses(Line 27c x \$5.85)	210,326	335,500 (KW)	\$0.63 /KW
33 Balance to Other Classes	15,739,358	633,993	2.48258
APPORTIONMENT OF NON-DEMAND COSTS			
34 Total Non-demand Costs(Line 31b)	32,757,511		
35 Total KWH Purchased (Line 12)		690,522 KWH	
36 Average Cost per KWH Purchased			4.74388
37 Average Cost Adjusted for Line Losses (Line 36 x 1.03)			4.88620
38 GSLD1 Non-demand Costs (Line 27a x Line 37)	1,481,682	23,648	6.26570
39 Balance to Other Classes	31,275,829	633,993	4.93315
GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a Total GSLD1 Demand Costs (Line 32)	210,326	335,500 (KW)	\$0.63 /KW
40b Revenue Tax Factor			1.00072
40c GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			\$0.63 /KW
40d Total Current GSLD1 Non-demand Costs(Line 38)	1,481,682	23,648	6.26570
40e Total Non-demand Costs Including True-up	1,481,682	23,648	6.26570
40f Revenue Tax Factor			1.00072
40g GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			6.27021
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	47,015,187	633,993	7.41573
41b Less: Total Demand Cost Recovery	15,739,358 ***		
41c Total Other Costs to be Recovered	31,275,829	633,993	4.93315
41d Unbilled Revenue	0	633,993	0.00000
41e Other Classes' Portion of True-up (Line 30c)	(2,257,470)	633,993	-0.35607
41f Total Demand & Non-demand Costs Including True-up	29,018,359	633,993	4.57708
42 Revenue Tax Factor			1.00072
43 Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	29,039,252		4.580

* For Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

FLORIDA DIVISION-CONSOLIDATED

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			(1)/(2)*8,760			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN	KWH At GEN	12 CP Demand Percentage	Energy Percentage
44 RS	316,043,494	58.270%	61,914.9	1.089	1.030	67,425.3	325,524,799	55.95%	49.85%
45 GS	54,618,537	57.224%	10,895.7	1.089	1.030	11,865.4	56,257,094	9.84%	8.62%
46 GSD	172,626,003	74.102%	26,593.2	1.089	1.030	28,960.0	177,804,783	24.03%	27.23%
47 GSLD	83,195,511	85.094%	11,160.8	1.089	1.030	12,154.1	85,691,377	10.08%	13.12%
48 LS	7,509,526	767.743%	111.7	1.089	1.030	121.6	7,734,811	0.10%	1.18%
49	0	767.743%	0.0	1.089	1.030	0.0	0	0.00%	0.00%
TOTAL	633,993,072		110,676.3			120,526.4	653,012,864	100.00%	100.00%

	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	12/13 * (8)	1/13 * (9)	(10) + (11) Demand Allocation Percentage	Tot. Col. 13 * (9)	(13)/(1)	(14) * 1.00072 Demand Cost Recovery Adj for Taxes	Other Charges	(15) + (16)
Rate Schedule	12/13 Of 12 CP	1/13 Of Energy		Demand Dollars	Demand Cost Recovery			Levelized Adjustment
50 RS	51.66%	3.84%	55.50%	\$8,735,344	0.02764	0.02766	0.04580	\$ 0.07346
51 GS	9.08%	0.66%	9.74%	1,533,013	0.02807	0.02809	0.04580	\$ 0.07389
52 GSD	22.18%	2.09%	24.27%	3,819,942	0.02213	0.02215	0.04580	\$ 0.06795
53 GSLD	9.30%	1.01%	10.31%	1,622,728	0.01950	0.01951	0.04580	\$ 0.06531
54 LS	0.09%	0.09%	0.18%	28,331	0.00377	0.00377	0.04580	\$ 0.04957
TOTAL	92.31%	7.69%	100.00%	\$15,739,358				

Step Rate Allocation for Residential Customers

	(18)	(19)	(20)	(21) (19) * (20)
Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
56 RS	Sales	316,043,494	\$0.07346	\$23,216,555
57 RS	<= 1,000kWh/mo.	225,842,812	\$0.06989	\$15,784,702
58 RS	> 1,000 kWh/mo.	90,200,683	\$0.08239	\$7,431,853
59 RS	Total Sales	316,043,494		\$23,216,555

(2) From Gulf Power 2018 Load Research results.

TOU Rates

	(22)	(23)	(24)	(25)
Rate Schedule	On Peak Rate Differential	Off Peak Rate Differential	Levelized Adj. On Peak	Levelized Adj. Off Peak
60 RS	0.0840	(0.0390)	\$0.15389	\$0.03089
61 GS	0.0400	(0.0500)	\$0.11389	\$0.02389
62 GSD	0.0400	(0.0325)	\$0.10795	\$0.03545
63 GSLD	0.0600	(0.0300)	\$0.12531	\$0.03531
64 Interruptible	(0.0150)	-	\$0.05031	\$0.06531

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FLORIDA PUBLIC UTILITIES COMPANY
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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2021 - DECEMBER 2021
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

FLORIDA DIVISION-CONSOLIDATED

Over-recovery of purchased power costs for the period January 2021 - December 2021. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True- Up and Interest Provision for the Twelve Month Period ended December 2021.)(Estimated)	\$ (2,257,470)
Portion of 2021 Over-recovery to be refunded for the period January 2022 - December 2022	\$ (2,257,470)
Estimated kilowatt hour sales for the months of January 2022 - December 2022 as per estimate filed with the Commission. (Excludes GSLD1 customers)	633,993,072
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2022- December 2022	-0.35607

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

LINE NO.		(a)	(b)	(c)	(d)	(e)	(f) ESTIMATED	(h)	(i)	(j)	(k)	(l)	(m)	(n) TOTAL PERIOD	LINE NO.
		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER		
1	FUEL COST OF SYSTEM GENERATION													0	1
1a	NUCLEAR FUEL DISPOSAL													0	1a
2	FUEL COST OF POWER SOLD													0	2
3	FUEL COST OF PURCHASED POWER	1,003,052	1,076,664	733,970	880,144	944,147	1,424,467	1,478,397	1,561,923	1,532,263	1,362,746	1,074,662	1,039,736	14,112,170	3
3a	DEMAND & NON FUEL COST OF PUR POWER	1,502,291	1,309,131	1,319,107	1,222,300	1,353,049	1,561,973	1,584,286	1,607,733	1,564,267	1,368,853	1,227,903	1,487,249	17,108,143	3a
3b	QUALIFYING FACILITIES	1,479,065	1,322,954	1,482,059	1,410,391	1,402,252	1,261,228	1,368,046	1,258,804	1,421,212	1,412,500	1,351,900	1,418,407	16,588,818	3b
4	OTHER FUEL RELATED COSTS	74,272	74,272	75,722	74,272	74,272	75,722	74,272	74,272	75,722	74,272	74,272	76,722	898,064	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	4,058,681	3,783,021	3,610,858	3,587,107	3,773,720	4,323,389	4,505,001	4,502,732	4,593,464	4,218,371	3,728,737	4,022,114	48,707,195	5
5a	LESS: TOTAL DEMAND COST RECOVERY	1,394,431	1,186,919	1,222,451	1,119,128	1,238,680	1,425,622	1,469,404	1,466,207	1,448,221	1,263,500	1,130,956	1,373,840	15,739,358	5a
5b	TOTAL OTHER COST TO BE RECOVERED	2,664,250	2,596,101	2,388,407	2,467,978	2,535,040	2,897,768	3,035,597	3,036,525	3,145,243	2,954,871	2,597,781	2,648,274	32,967,837	5b
6	APPORTIONMENT TO GSLD1 CLASS	138,100	221,553	156,195	106,245	64,063	110,067	94,273	145,928	122,255	163,876	239,239	130,214	1,692,008	6
6a	BALANCE TO OTHER CLASSES	2,526,151	2,374,548	2,232,212	2,361,733	2,470,978	2,787,701	2,941,324	2,890,597	3,022,988	2,790,995	2,358,542	2,518,060	31,275,829	6a
6b	SYSTEM KWH SOLD (MWH)	51,373	50,445	42,494	45,717	49,071	60,734	63,545	64,753	65,261	60,414	51,313	52,520	657,641	6b
7	GSLD1 MWH SOLD	1,826	2,906	1,806	1,165	606	1,476	1,630	2,181	2,044	2,676	3,634	1,696	23,548	7
7a	BALANCE MWH SOLD OTHER CLASSES	49,546	47,539	40,688	44,552	48,465	59,257	61,915	62,572	63,217	57,738	47,680	50,824	633,993	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES	5.09856	4.99493	5.48618	5.30109	5.09849	4.70439	4.75057	4.61966	4.78191	4.8339	4.94664	4.95449	4.93315	7b
8	JURISDICTIONAL LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)	5.09856	4.99493	5.48618	5.30109	5.09849	4.70439	4.75057	4.61966	4.78191	4.83390	4.94664	4.95449	4.93315	9
10	PROJECTED UNBILLED REVENUES(CENTS/KWH)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	10
11	GPIF (CENTS/KWH)														11
12	TRUE-UP (CENTS/KWH)	(2,257,470)	(0.35607)	(0.35607)	(0.35607)	(0.35607)	(0.35607)	(0.35607)	(0.35607)	(0.35607)	(0.35607)	(0.35607)	(0.35607)	(0.35607)	12
13	TOTAL	4.74249	4.63886	5.13011	4.94502	4.74242	4.34832	4.39450	4.26359	4.42584	4.47783	4.59057	4.59842	4.57708	13
14	REVENUE TAX FACTOR	0.00072	0.00341	0.00334	0.00369	0.00356	0.00341	0.00313	0.00316	0.00307	0.00319	0.00322	0.00331	0.00330	14
15	RECOVERY FACTOR ADJUSTED FOR TAXES	4.74590	4.64220	5.13380	4.94858	4.74583	4.35145	4.39766	4.26666	4.42903	4.48105	4.59388	4.60173	4.58038	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH	4.746	4.642	5.134	4.949	4.746	4.351	4.398	4.267	4.429	4.481	4.594	4.602	4.580	16

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FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH		TOTAL \$ FOR FUEL ADJ. (7) x (8) (A)
							(A) FUEL COST	(B) TOTAL COST	
JANUARY 2022	FPL / GULF POWER	MS	37,376,278			37,376,278	2.683660	6.853989	1,003,052
FEBRUARY 2022	FPL / GULF POWER	MS	38,055,687			38,055,687	2.829180	6.417482	1,076,664
MARCH 2022	FPL / GULF POWER	MS	28,592,000			28,592,000	2.567048	7.377934	733,970
APRIL 2022	FPL / GULF POWER	MS	32,867,279			32,867,279	2.677873	6.568435	880,144
MAY 2022	FPL / GULF POWER	MS	36,418,144			36,418,144	2.592518	6.462762	944,147
JUNE 2022	FPL / GULF POWER	MS	50,099,607			50,099,607	2.843269	6.073623	1,424,467
JULY 2022	FPL / GULF POWER	MS	52,129,781			52,129,781	2.835993	5.983346	1,478,397
AUGUST 2022	FPL / GULF POWER	MS	54,410,518			54,410,518	2.870627	5.929145	1,561,923
SEPTEMBER 2022	FPL / GULF POWER	MS	52,974,315			52,974,315	2.892463	5.951850	1,532,263
OCTOBER 2022	FPL / GULF POWER	MS	48,027,911			48,027,911	2.837404	5.805003	1,362,746
NOVEMBER 2022	FPL / GULF POWER	MS	38,939,399			38,939,399	2.759831	6.058098	1,074,662
DECEMBER 2022	FPL / GULF POWER	MS	39,718,469			39,718,469	2.617764	6.504296	1,039,736
TOTAL			509,609,388	0	0	509,609,388	2.769213	6.259182	14,112,170

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH		TOTAL \$ FOR FUEL ADJ. (7) x (8) (A)
								(A) FUEL COST	(B) TOTAL COST	
JANUARY	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		16,565,000			16,565,000	8.928856	8.928856	1,479,065
FEBRUARY	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		14,912,000			14,912,000	8.871741	8.871741	1,322,954
MARCH	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		16,026,900			16,026,900	9.247322	9.247322	1,482,059
APRIL	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,135,400			15,135,400	9.318492	9.318492	1,410,391
MAY	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,106,600			15,106,600	9.282380	9.282380	1,402,252
JUNE	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		13,670,700			13,670,700	9.225775	9.225775	1,261,228
JULY	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		14,592,700			14,592,700	9.374866	9.374866	1,368,046
AUGUST	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		13,580,000			13,580,000	9.269543	9.269543	1,258,804
SEPTEMBER	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,549,600			15,549,600	9.139862	9.139862	1,421,212
OCTOBER	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,407,000			15,407,000	9.167911	9.167911	1,412,500
NOVEMBER	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		14,939,700			14,939,700	9.049044	9.049044	1,351,900
DECEMBER	2022	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,427,600			15,427,600	9.193958	9.193958	1,418,407
TOTAL				180,913,200	0	0	180,913,200	9.169490	9.169490	16,588,818

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FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

	JANUARY 2022	FEBRUARY 2022	MARCH 2022	APRIL 2022	MAY 2022	JUNE 2022	JULY 2022
BASE RATE REVENUES ** \$	54.82	54.82	54.82	54.82	54.82	54.82	54.82
FUEL RECOVERY FACTOR CENTS/KWH	6.99	6.99	6.99	6.99	6.99	6.99	6.99
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES \$	69.89	69.89	69.89	69.89	69.89	69.89	69.89
GROSS RECEIPTS TAX	3.20	3.20	3.20	3.20	3.20	3.20	3.20
TOTAL REVENUES *** \$	127.91	127.91	127.91	127.91	127.91	127.91	127.91

	AUGUST 2022	SEPTEMBER 2022	OCTOBER 2022	NOVEMBER 2022	DECEMBER 2022	PERIOD TOTAL
BASE RATE REVENUES ** \$	54.82	54.82	54.82	54.82	54.82	657.84
FUEL RECOVERY FACTOR CENTS/KWH	6.99	6.99	6.99	6.99	6.99	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES \$	69.89	69.89	69.89	69.89	69.89	838.68
GROSS RECEIPTS TAX	3.20	3.20	3.20	3.20	3.20	38.40
TOTAL REVENUES *** \$	127.91	127.91	127.91	127.91	127.91	1,534.92

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	16.95
CENTS/KWH	23.73
CONSERVATION FACTOR	1.34
STORM SURCHARGE	
(Michael/Dorian)	12.80
	<u>54.82</u>

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*** EXCLUDES FRANCHISE TAXES

TAMPA ELECTRIC COMPANY

FUEL AND PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

FUEL AND PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY
INDEX

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EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE

DOCUMENT NO. 1

FINAL CAPACITY OVER/ (UNDER) RECOVERY
FOR JANUARY 2020 - DECEMBER 2020

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

1. Actual End-of-Period True-up: Over/(Under) Recovery	(\$1,583,299)
2. Less: Actual/Estimated Over/(Under) Recovery Per Order No. PSC-2020-0439-FOF-EI For the January 2020 Through December 2020 Period	<u>1,771,480</u>
3. Final True-up: Over/(Under) Recovery to Be Carried Forward to the January 2022 Through December 2022 Period	<u>(\$3,354,779)</u>

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	Total
1 UNIT POWER CAPACITY CHARGES	497,430	343,840	10,263	693,766	662,599	916,608	825,073	1,284,262	1,012,685	788,175	780,735	1,139,692	8,955,128
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3 SCHEDULE J.D. & EMERG CAPACITY CHARGES	0	0	0	0	0	0	0	0	0	0	0	0	0
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0	0	0	0	0	0	0	0	0	0
5 (CAPACITY REVENUES)	(89,627)	(69,063)	(86,008)	(82,178)	(81,226)	(69,792)	(61,911)	(51,634)	(71,008)	(193,392)	(65,093)	(82,468)	(1,003,400)
6 TOTAL CAPACITY DOLLARS	407,803	274,777	(75,745)	611,588	581,373	846,816	763,162	1,232,628	941,677	594,783	715,642	1,057,224	7,951,728
7 JURISDICTIONAL PERCENTAGE	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000
8 JURISDICTIONAL CAPACITY DOLLARS	407,803	274,777	(75,745)	611,588	581,373	846,816	763,162	1,232,628	941,677	594,783	715,642	1,057,224	7,951,728
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	120,339	117,655	116,622	131,999	132,306	(189,542)	(214,917)	(216,974)	(205,669)	(191,724)	(177,780)	(155,903)	(733,588)
10 PRIOR PERIOD TRUE-UP PROVISION	(181,601)	(181,601)	(181,601)	(181,601)	(181,601)	419,815	419,815	419,815	419,815	419,815	419,815	419,817	2,030,702
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	(61,262)	(63,946)	(64,979)	(49,602)	(49,295)	230,273	204,898	202,841	214,146	228,091	242,035	263,914	1,297,114
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	(469,065)	(338,723)	10,766	(661,190)	(630,668)	(616,543)	(558,264)	(1,029,787)	(727,531)	(366,692)	(473,607)	(793,310)	(6,654,614)
13 INTEREST PROVISION FOR PERIOD	(3,096)	(12)	3,826	2,182	110	250	416	294	131	47	8	(98)	4,058
14 OTHER ADJUSTMENT	0	4,856,329	0	0	0	4,069,905	0	0	0	239,712	0	0	9,165,946
15 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(2,067,989)	(2,358,549)	2,340,646	2,536,839	2,059,432	1,610,475	4,644,273	3,666,610	2,217,302	1,070,088	523,340	(370,074)	(2,067,989)
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	181,601	181,601	181,601	181,601	181,601	(419,815)	(419,815)	(419,815)	(419,815)	(419,815)	(419,815)	(419,817)	(2,030,702)
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	(2,358,549)	2,340,646	2,536,839	2,059,432	1,610,475	4,644,273	3,666,610	2,217,302	1,070,088	523,340	(370,074)	(1,583,299)	(1,583,299)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	Total
1 BEGINNING TRUE-UP AMOUNT	(2,067,989)	(2,358,549)	2,340,646	2,536,839	2,059,432	1,610,475	4,644,273	3,666,610	2,217,302	1,070,088	523,340	(370,074)	(2,067,989)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST (LINE 1 + LINE 2)	(2,355,453)	2,340,658	2,533,013	2,057,250	1,610,365	4,644,022	3,666,194	2,217,008	1,069,956	283,581	(370,082)	(1,583,201)	(10,753,305)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT.	(4,423,442)	(17,891)	4,873,659	4,594,089	3,669,797	6,254,497	8,310,467	5,883,618	3,287,258	1,353,669	153,258	(1,953,275)	(12,821,294)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(2,211,721)	(8,946)	2,436,830	2,297,045	1,834,899	3,127,249	4,155,234	2,941,809	1,643,629	676,835	76,629	(976,638)	(6,410,647)
5 INTEREST RATE % - 1ST DAY OF MONTH	1.710	1.640	1.560	2.210	0.060	0.080	0.110	0.120	0.130	0.070	0.100	0.140	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	1.640	1.560	2.210	0.060	0.080	0.110	0.120	0.130	0.070	0.100	0.140	0.100	NA
7 TOTAL (LINE 5 + LINE 6)	3.350	3.200	3.770	2.270	0.140	0.190	0.230	0.250	0.200	0.170	0.240	0.240	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	1.675	1.600	1.885	1.135	0.070	0.095	0.115	0.125	0.100	0.085	0.120	0.120	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.140	0.133	0.157	0.095	0.006	0.008	0.010	0.010	0.008	0.007	0.010	0.010	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(3,096)	(12)	3,826	2,182	110	250	416	294	131	47	8	(98)	4,058

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

	(1)	(2)	(3)	(4)
	ACTUAL	Per Mid-Course ESTIMATED	VARIANCE (1) - (2)	% CHANGE (3)/(2)
1 UNIT POWER CAPACITY CHARGES	\$8,955,128	\$3,091,870	\$5,863,258	189.63%
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0.00%
3 SCHEDULE J & D CAPACITY CHARGES	0	0	0	0.00%
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0.00%
5 (CAPACITY REVENUES)	(1,003,400)	(1,488,947)	485,547	-32.61%
6 TOTAL CAPACITY DOLLARS	\$7,951,728	\$1,602,923	\$6,348,805	396.08%
7 JURISDICTIONAL PERCENTAGE	100.00%	100.00%	0	0.00%
8 JURISDICTIONAL CAPACITY DOLLARS	\$7,951,728	1,602,923	\$6,348,805	396.08%
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	(733,588)	(708,529)	(25,059)	3.54%
10 PRIOR PERIOD TRUE-UP PROVISION	2,030,702	2,030,702	0	0.00%
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	\$1,297,114	\$1,322,173	(\$25,059)	-1.90%
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	(\$6,654,614)	(\$280,750)	(\$6,373,864)	2270.30%
13 INTEREST PROVISION FOR PERIOD	4,058	35,570	(31,512)	-88.59%
14 OTHER ADJUSTMENT	9,165,946	4,856,329	4,309,617	88.74%
15 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(2,067,989)	(2,067,989)	0	0.00%
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	(2,030,702)	(2,030,702)	0	0.00%
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	(\$1,583,299)	\$512,458	(\$2,095,757)	-408.96%

EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/ (UNDER) RECOVERY
FOR
JANUARY 2020 - DECEMBER 2020

TAMPA ELECTRIC COMPANY
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2020 THROUGH DECEMBER 2020

1 TOTAL FUEL COSTS FOR THE PERIOD	\$ 488,777,177
2 JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	488,777,177
3 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	<u>448,829,432</u>
4 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD (LINE 3 - LINE 2)	\$ (39,947,745)
5 ADJUSTMENTS	236,322
6 INTEREST	113,372
7 TRUE-UP COLLECTED	12,809,180
8 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/19)	<u>5,079,072</u>
9 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7 + LINE 8)	\$ (21,709,799)
10 PROJECTED OVER/(UNDER) RECOVERY PER PROJECTION FILED 9/3/20 (SCHEDULE E1-A LINE 6)	<u>(25,479,055)</u>
11 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 9 - LINE 10)	<u><u>\$ 3,769,256</u></u>

EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

ORIGINAL ESTIMATES

JANUARY 2020 – DECEMBER 2020

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. ORIGINAL ESTIMATES
FOR THE PERIOD
JANUARY 2020 THROUGH DECEMBER 2020

	ACTUAL	per Mid-Course ESTIMATED	VARIANCE AMOUNT	%
A 1. FUEL COST OF SYSTEM NET GENERATION	\$414,937,244	\$442,544,128	(\$27,606,884)	(6.2)
2. FUEL COST OF POWER SOLD	1,246,248	276,696	969,552	350.4
2a. GAINS FROM SALES	481,866	28,000	453,866	1,621.0
3. FUEL COST OF PURCHASED POWER	23,076,596	906,840	22,169,756	2,444.7
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
3b. PAYMENT TO QUALIFIED FACILITIES	2,385,071	3,504,446	(1,119,375)	(31.9)
4. ENERGY COST OF ECONOMY PURCHASES	48,910,108	43,677,130	5,232,978	12.0
6a. ADJ. - BIG BEND UNITS 1-4 IGNITERS CONVERSION PROJECT	1,657,276	1,657,348	(72)	0.0
6b. TRANSCO REFUND	(461,004)	0	(461,004)	0.0
6c. ADJ.	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR. TRANS. (SUM OF LINES A1 THRU 6c)	\$488,777,177	\$491,985,196	(\$3,208,019)	(0.7)
C 1. JURISDICTIONAL FUEL REVENUE	\$550,238,491	\$536,685,756	\$13,552,735	2.5
2. FUEL ADJUSTMENT NOT APPLICABLE	(83,338,196)	(81,386,391)	(1,951,805)	2.4
2a. TRUE-UP PROVISION	(12,809,180)	(12,809,180)	0	0.0
2b. INCENTIVE PROVISION	(4,141,330)	(4,141,330)	0	0.0
2c. 2018 OPTIMIZATION MECHANISM GAIN	(1,120,353)	(1,120,353)	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2c)	\$448,829,432	\$437,228,502	\$11,600,930	2.7
6d. JURISD. TOTAL FUEL & NET PWR. TRANS.	488,777,177	491,985,196	(3,208,019)	(0.7)
7. TRUE-UP PROV.- THIS PER. (LINE C3-C6d)	(\$39,947,745)	(\$54,756,694)	\$14,808,949	(27.0)
7a. FUEL SAVINGS CREDIT FOR LAKE HANCOCK GENERATION PER SECOND SoBRA STIPULATION	236,322	236,322	0	0.0
8. INTEREST PROVISION - THIS PERIOD	113,372	38,365	75,007	195.5
TOTAL TRUE-UP AMOUNT FOR PERIOD (LINE 7 through 8)	(\$39,598,051)	(\$54,482,007)	\$14,883,956	(27.3)
9. TRUE-UP & INT. PROV. BEG. OF PERIOD (Beginning January 2020)	5,079,072	5,079,072	0	0.0
10. TRUE-UP COLLECTED (REFUNDED)	12,809,180	12,809,180	0	0.0
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C8 through C10)	(\$21,709,799)	(\$36,593,754)	\$14,883,955	(40.7)

EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE

DOCUMENT NO. 4

FUEL AND PURCHASED POWER COST
RECOVERY YTD DECEMBER 2020

SCHEDULES A1 AND A2
AND
SCHEDULES A6 THROUGH A9
AND
SCHEDULE A12

**FUEL AND PURCHASED POWER COST RECOVERY
SCHEDULES A1 AND A2**

DECEMBER 2020

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: December 2020

	\$		DIFFERENCE		MWH		DIFFERENCE		CENTSIKWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	38,374,683	41,515,051	(3,140,368)	-7.6%	1,351,236	1,499,740	(148,504)	-9.9%	2,83997	2,76815	0.07182	2.6%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adjustments - Big Bend Units 1-4 Igniters Conversion Project	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	38,374,683	41,515,051	(3,140,368)	-7.6%	1,351,236	1,499,740	(148,504)	-9.9%	2,83997	2,76815	0.07182	2.6%
6. Fuel Cost of Purchased Power - Firm (A7)	4,925,108	810,650	4,114,458	507.6%	144,935	21,860	123,075	583.0%	3,39815	3,70837	(0.31022)	-8.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A8)	919,104	417,970	501,134	119.9%	24,756	27,470	(2,714)	-9.9%	3,71265	1,52155	2,19110	144.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities & Net Metering (A8)	281,644	293,490	(11,846)	-4.0%	13,254	10,380	2,874	27.7%	2,12497	2,82746	(0.70248)	-24.8%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	6,125,856	1,522,110	4,603,746	302.5%	182,945	59,710	123,235	206.4%	3,34847	2,54917	0.79930	31.4%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,534,181	1,559,450	(25,269)	-1.6%				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	65,857	13,930	51,927	372.8%	3,377	580	2,797	482.2%	1,95016	2,40172	(0.45156)	-18.8%
15. Fuel Cost of Sch. C/CB Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of OATT Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Market Base Sales (A6)	7,018	0	7,018	0.0%	1,240	0	1,240	0.0%	0.56597	0.00000	0.56597	0.0%
18. Gains on Sales	39,982	877	39,105	4459.0%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES	112,857	14,807	98,050	662.2%	4,617	580	4,037	696.0%	2,44438	2,55293	(0.10855)	-4.3%
(LINE 14 + 15 + 16 + 17 + 18)												
20. Net Inadvertent Interchange			(631)			0	(631)	0.0%				
21. Wheeling Rec'd. less Wheeling Deliv'd.			1,607			0	1,607	0.0%				
22. Interchange and Wheeling Losses			1,689			26	1,663	6458.7%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS	44,387,682	43,022,354	1,365,328	3.2%	1,528,851	1,558,844	(29,993)	-1.9%	2,90334	2,75989	0.14345	5.2%
(LINE 5 + 12 - 19 + 20 + 21 - 22)												
24. Net Unbilled	(492,841)	1,000,542	(1,493,383)	-149.3%	(16,975)	36,253	(53,228)	-146.8%	2,90333	2,75989	0.14345	5.2%
25. Company Use	80,626	85,557	(4,931)	-5.8%	2,777	3,100	(323)	-10.4%	2,90335	2,75990	0.14345	5.2%
26. T & D Losses	2,441,270	2,541,808	(100,538)	-4.0%	84,085	92,098	(8,013)	-8.7%	2,90334	2,75989	0.14345	5.2%
27. System KWH Sales	44,387,682	43,022,354	1,365,328	3.2%	1,458,964	1,427,393	31,571	2.2%	3,04241	3,01405	0.02836	0.9%
28. Wholesale KWH Sales	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
29. Jurisdictional KWH Sales	44,387,682	43,022,354	1,365,328	3.2%	1,458,964	1,427,393	31,571	2.2%	3,04241	3,01405	0.02836	0.9%
30. Jurisdictional Loss Multiplier									1,00000	1,00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	44,387,682	43,022,354	1,365,328	3.2%	1,458,964	1,427,393	31,571	2.2%	3,04241	3,01405	0.02836	0.9%
32. 2018 Optimization Mechanism Gain	93,360	93,360	0	0.0%	1,458,964	1,427,393	31,571	2.2%	0.00640	0.00654	(0.00014)	-2.2%
33. True-up *	0	0	0	0.0%	1,458,964	1,427,393	31,571	2.2%	0.00000	0.00000	0.00000	0.0%
34. Fuel savings credit for Lake Hancock generation per Second SoBRA stipulation	0	0	0	0.0%	1,458,964	1,427,393	31,571	2.2%	0.00000	0.00000	0.00000	0.0%
35. Total Jurisdictional Fuel Cost (Excl. GPIF)	44,481,042	43,115,714	1,365,328	3.2%	1,458,964	1,427,393	31,571	2.2%	3,04881	3,02059	0.02822	0.9%
36. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
37. Fuel Cost Adjusted for Taxes (Excl. GPIF)	44,513,068	43,146,757	1,366,311	3.2%	1,458,964	1,427,393	31,571	2.2%	3,05101	3,02277	0.02824	0.9%
38. GPIF * (Already Adjusted for Taxes)	345,109	345,109	0	0.0%	1,458,964	1,427,393	31,571	2.2%	0.02365	0.02418	(0.00052)	-2.2%
39. Fuel Cost Adjusted for Taxes (Incl. GPIF)	44,858,177	43,491,866	1,366,311	3.1%	1,458,964	1,427,393	31,571	2.2%	3,07466	3,04695	0.02772	0.9%
40. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.075	3.047	0.028	0.9%

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: December 2020

	ACTUAL		ESTIMATED		DIFFERENCE		MWH		CENTSIKWH		DIFFERENCE	
	AMOUNT	%	AMOUNT	%	AMOUNT	%	ACTUAL	ESTIMATED	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	414,937,244		442,544,128	-6.2%	(27,606,884)		18,545,260	18,956,176	2,237,43	2,334,56	(10,916)	-2.2%
2. Spent Nuclear Fuel Disposal Cost	0	0.0%	0	0.0%	0	0.0%	0	0	0.00000	0.00000	(0.09713)	-4.2%
3. Coal Car Investment	0	0.0%	0	0.0%	0	0.0%	0	0	0.00000	0.00000	0.00000	0.0%
4a. Adjustments - Big Bend Units 1-4 Igniters Conversion Project	1,657,276	(72)	1,657,348				0	0	0.00000	0.00000	0.00000	0.0%
4b. Adjustments	(461,004)		0	0.0%	(461,004)		0	0	0.00000	0.00000	0.00000	0.0%
4c. Adjustments	0	0.0%	0	0.0%	0	0.0%	0	0	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	416,133,516	-6.3%	444,201,476		(28,067,960)		18,545,260	18,956,176	2,243,88	2,343,31	(10,916)	-4.2%
6. Fuel Cost of Purchased Power - Firm (A7)	23,076,596	2444.7%	906,840		22,169,756		664,154	23,940	3,474,59	3,787,97	(640,214)	-2674.2%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	48,910,108		43,677,130	12.0%	5,232,978		1,811,117	1,799,649	2,700,55	2,426,98	11,468	0.6%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0.0%	0	0.0%	0	0.0%	0	0	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0.0%	0	0.0%	0	0.0%	0	0	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0.0%	0	0.0%	0	0.0%	0	0	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities & Net Metering (A9)	2,385,071		3,504,446	-31.9%	(1,119,375)		135,372	123,937	1,761,96	2,877,60	(11,435)	9.2%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	74,371,775	54.7%	48,088,416		26,283,359		2,610,643	1,947,526	2,848,79	2,469,21	663,117	34.0%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)							21,155,903	20,903,702	1.2%		252,201	1.2%
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	619,642		256,411	141.7%	363,231		38,097	13,365	1,626,49	1,918,53	(24,732)	185.1%
15. Fuel Cost of Sch. C/CB Sales (A6)	0	0.0%	0	0.0%	0	0.0%	0	0	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of OATT Sales (A6)	0	0.0%	0	0.0%	0	0.0%	0	0	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Market Base Sales (A6)	626,606		20,285	2989.0%	606,321		37,643	1,050	3,485,0%	1,664,60	36,593	3485.0%
18. Gains on Sales	481,866		28,000	1621.0%	453,866							
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	1,728,114	467.2%	304,696		1,423,418		75,740	14,415	2.28164	2.11374	61,325	425.4%
20. Net Inadvertent Interchange							(1,309)	0	0.0%		(1,309)	0.0%
21. Wheeling Rec'd. less Wheeling Delvd.							20,547	0	0.0%		20,547	0.0%
22. Interchange and Wheeling Losses							22,045	307	7085.4%		21,738	7085.4%
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	488,777,177	-0.7%	491,985,196		(3,208,019)		21,077,356	20,888,980	0.9%	2,31897	188,376	0.9%
24. Net Unbilled	391,583 (a)		3,206,806 (a)	-87.8%	(2,815,223)		152,755	190,461	0.25635	1.68371	(37,706)	-19.8%
25. Company Use	845,984 (a)		874,475 (a)	-3.3%	(28,491)		36,272	37,200	2.33233	2.35074	(928)	-2.5%
26. T & D Losses	21,428,196 (a)		28,181,740 (a)	-24.0%	(6,753,544)		938,277	1,173,262	2.28378	2.40200	(234,985)	-20.0%
27. System KWH Sales	488,777,177		491,985,196	-0.7%	(3,208,019)		19,950,052	19,488,057	461,995	2,524,55	461,995	2.4%
28. Wholesale KWH Sales	0	0.0%	0	0.0%	0	0.0%	0	0	0.00000	0.00000	0.00000	0.0%
29. Jurisdictional KWH Sales	488,777,177		491,985,196	-0.7%	(3,208,019)		19,950,052	19,488,057	461,995	2,524,55	461,995	2.4%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	488,777,177		491,985,196	-0.7%	(3,208,019)		19,950,052	19,488,057	461,995	2,524,55	461,995	2.4%
32. 2018 Optimization Mechanism Gain	1,120,353		1,120,353	0.0%	0	0.0%	19,950,052	19,488,057	0.00562	0.00575	(0.00013)	-2.3%
33. True-up *	12,809,180		12,809,180	0.0%	0	0.0%	19,950,052	19,488,057	0.06421	0.06573	(0.00152)	-2.3%
34. stipulation	(236,322)		(236,322)	0.0%	0	0.0%	19,950,052	19,488,057	(0.00118)	(0.00121)	0.00003	-2.3%
35. Total Jurisdictional Fuel Cost (Excl. GPIF)	502,470,388		505,678,407	-0.6%	(3,208,019)		19,950,052	19,488,057	2.51864	2.59481	(76,417)	-2.9%
36. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
37. Fuel Cost Adjusted for Taxes (Excl. GPIF)	502,832,167		506,042,496	-0.6%	(3,210,329)		19,950,052	19,488,057	2.52046	2.59668	(76,617)	-2.9%
38. GPIF + (Already Adjusted for Taxes)	4,141,330		4,141,330	0.0%	0	0.0%	19,950,052	19,488,057	0.02076	0.02125	(0.00049)	-2.3%
39. Fuel Cost Adjusted for Taxes (Incl. GPIF)	506,973,497	-0.6%	510,183,826		(3,210,329)		19,950,052	19,488,057	2.54122	2.61793	(461,995)	2.4%
40. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.541	2.618	(0.077)	-2.9%

* Based on Jurisdictional Sales (a) Included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2020

	CURRENT MONTH			PERIOD TO DATE		
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT %
A. FUEL COST & NET POWER TRANSACTION						
1. FUEL COST OF SYSTEM NET GENERATION	38,374,683	41,515,051	(3,140,368) -7.6%	414,937,244	442,544,128	(27,606,884) -6.2%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0 0.0%	0	0	0 0.0%
2. FUEL COST OF POWER SOLD	72,875	13,930	58,945 423.2%	1,246,248	276,696	969,552 350.4%
2a. GAINS FROM SALES	39,982	877	39,105 4459.0%	481,866	28,000	453,866 1621.0%
3. FUEL COST OF PURCHASED POWER	4,925,108	810,650	4,114,458 507.6%	23,076,596	906,840	22,169,756 2444.7%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0 0.0%	0	0	0 0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	281,644	293,490	(11,846) -4.0%	2,385,071	3,504,446	(1,119,375) -31.9%
4. ENERGY COST OF ECONOMY PURCHASES	919,104	417,970	501,134 119.9%	48,910,108	43,677,130	5,232,978 12.0%
5. TOTAL FUEL & NET POWER TRANSACTION	44,387,682	43,022,354	1,365,328 3.2%	487,580,905	490,327,848	(2,746,943) -0.6%
6a. ADJ. - BIG BEND UNITS 1-4 IGNITERS CONVERSION PROJECT	0	0	0 0.0%	1,657,276	1,657,348	(72) 0.0%
6b. TRANSCO REFUND	0	0	0 0.0%	(461,004)	0	(461,004) 0.0%
6c. ADJUSTMENT	0	0	0 0.0%	0	0	0 0.0%
7. ADJUSTED TOTAL FUEL & NET PWR. TRANS.	44,387,682	43,022,354	1,365,328 3.2%	488,777,177	491,985,196	(3,208,019) -0.7%
B. MWH SALES						
1. JURISDICTIONAL SALES	1,458,964	1,427,393	31,571 2.2%	19,950,343	19,488,057	462,286 2.4%
2. NONJURISDICTIONAL SALES	0	0	0 0.0%	0	0	0 0.0%
3. TOTAL SALES	1,458,964	1,427,393	31,571 2.2%	19,950,343	19,488,057	462,286 2.4%
4. JURISDIC. SALES-% TOTAL MWH SALES	1.0000000	1.0000000	0.0000000 0.0%	1.0000000	1.0000000	0.0000000 0.0%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2020

	CURRENT MONTH			PERIOD TO DATE		
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT %
C. TRUE-UP CALCULATION						
1. JURISDICTIONAL FUEL REVENUE	37,473,893	36,600,298	873,595 2.4%	550,238,491	536,685,756	13,552,735 2.5%
2. JURISDICTIONAL FUEL REVENUE CREDIT	0	0	0 0.0%	(83,338,196)	(81,386,391)	(1,951,805) 2.4%
2a. TRUE-UP PROVISION	0	0	0 0.0%	(12,809,180)	(12,809,180)	0 0.0%
2b. GPIF PROVISION	(345,109)	(345,109)	0 0.0%	(4,141,330)	(4,141,330)	0 0.0%
2c. 2018 OPTIMIZATION MECHANISM GAIN	(93,360)	(93,360)	0 0.0%	(1,120,353)	(1,120,353)	0 0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	37,035,424	36,161,829	873,595 2.4%	448,829,432	437,228,502	11,600,930 2.7%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	44,387,682	43,022,354	1,365,328 3.2%	488,777,177	491,985,196	(3,208,019) -0.7%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	1,000,000	1,000,000	0.000000 0.0%	-	-	- -
6. JURISDIC. TOTAL FUEL & NET PWR. TRANS.	44,387,682	43,022,354	1,365,328 3.2%	488,777,177	491,985,196	(3,208,019) -0.7%
6a. JURISDIC. LOSS MULTIPLIER	1,00000	1,00000	0.00000 0.0%	-	-	- -
6b. (LINE C6 x LINE C6a)	44,387,682	43,022,354	1,365,328 3.2%	488,777,177	491,985,196	(3,208,019) -0.7%
6c. ADJUSTMENT	0	0	0 0.0%	0	0	0 0.0%
6d. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6c)	44,387,682	43,022,354	1,365,328 3.2%	488,777,177	491,985,196	(3,208,019) -0.7%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6d)	(7,352,258)	(6,860,525)	(491,733) 7.2%	(39,947,745)	(64,756,694)	14,808,949 -27.0%
8. INTEREST PROVISION FOR THE MONTH	-1803	-59257	57,454 -97.0%	113,372	38,365	75,007 195.5%
9. FUEL SAVINGS CREDIT FOR LAKE HANCOCK GENERATION PER SECOND SABRA STIPULATION	0	0	0 0.0%	236,322	236,322	0 0.0%
10. TRUE-UP & INT. PROV. BEG. OF MONTH	(14,355,738)	(29,673,972)	15,318,234 -51.6%	-----NOT APPLICABLE-----	-----NOT APPLICABLE-----	-----NOT APPLICABLE-----
11. TRUE-UP COLLECTED (REFUNDED)	0	0	0 0.0%	-----NOT APPLICABLE-----	-----NOT APPLICABLE-----	-----NOT APPLICABLE-----
12. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C11)	(21,709,799)	(36,593,754)	14,883,955 -40.7%	-----NOT APPLICABLE-----	-----NOT APPLICABLE-----	-----NOT APPLICABLE-----

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2020

	CURRENT MONTH			PERIOD TO DATE		
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT %
D. INTEREST PROVISION						
1. BEGINNING TRUE-UP AMOUNT (LINE C10)	(14,355,738)	(29,673,972)	15,318,234 -51.6%			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10 + C11)	(21,707,996)	(36,534,497)	14,826,501 -40.6%			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(36,063,734)	(66,208,469)	30,144,735 -45.5%			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(18,031,867)	(33,104,235)	15,072,368 -45.5%			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	0.140	2.150	(2.010) -93.5%			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	0.100	2.150	(2.050) -95.3%			
7. TOTAL (LINE D5 + LINE D6)	0.240	4.300	(4.060) -94.4%			
8. AVERAGE INT. RATE (50% OF LINE D7)	0.120	2.150	(2.030) -94.4%			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.010	0.179	(0.169) -94.4%			
10. INT. PROVISION (LINE D4 x LINE D9)	(1,803)	(59,257)	57,454 -97.0%			

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2020 - DECEMBER 2020

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)		(3)	(4)	(5)	(6)		(7)	(8)	(9)
SOLD TO	TYPE & SCHEDULE		TOTAL MWH SOLD	MWH WHEELED OTHER SYSTEM	MWH FROM OWN GENERATION	CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT (5)X(6A)	TOTAL \$ FOR TOTAL COST (5)X(6B)	GAINS ON MARKET BASED SALES
						(A) FUEL COST	(B) TOTAL COST			
ESTIMATED:										
SEMINOLE	JURISD.	SCH. - D	13,365.0	0.0	13,365.0	1.919	2.078	256,410.87	277,747.96	16,453.36
VARIOUS	JURISD.	MKT.BASE	1,050.0	0.0	1,050.0	1.932	3.174	20,284.50	33,326.26	11,546.26
TOTAL			14,415.0	0.0	14,415.0	1.919	2.158	276,695.37	311,074.22	27,999.62
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISD.	SCH. - D	38,097.0	0.0	38,097.0	1.626	1.789	619,642.84	681,607.14	42,811.68
CITY OF TALLAHASSEE		SCH. - MA	75.0	0.0	75.0	1.366	3.338	1,024.65	2,503.34	1,310.54
DUKE ENERGY FLORIDA		SCH. - MA	6,000.0	0.0	6,000.0	1.577	2.633	94,638.00	158,001.14	52,507.14
EXGEN		SCH. - MA	65.0	0.0	65.0	2.635	4.329	1,712.75	2,813.57	940.92
FLORIDA POWER & LIGHT		SCH. - MA	3,771.0	0.0	3,771.0	2.393	3.647	90,221.68	137,513.14	41,341.96
MORGAN STANLEY		SCH. - MA	200.0	0.0	200.0	1.370	0.232	2,740.00	463.46	(2,658.54)
NEW SMYRNA BEACH		SCH. - MA	230.0	0.0	230.0	1.971	3.659	4,533.40	8,416.77	3,455.57
ORLANDO UTILITIES		SCH. - MA	5,625.0	0.0	5,625.0	1.568	2.651	88,180.35	149,122.98	48,615.73
ORLANDO UTILITIES COMMISSION		SCH. - MA	10,200.0	0.0	10,200.0	1.729	3.055	176,379.00	311,641.50	124,650.50
CITY OF LAKELAND		SCH. - MA	4,450.0	0.0	4,450.0	1.542	3.015	68,613.00	134,184.16	64,758.66
SOUTHERN COMPANY		SCH. - MA	1,275.0	0.0	1,275.0	0.524	3.180	6,675.00	40,547.62	33,150.62
THE ENERGY AUTHORITY		SCH. - MA	5,752.0	0.0	5,752.0	1.597	2.941	91,886.05	169,157.96	70,980.19
SUB-TOTAL			75,740.0	0.0	75,740.0	1.645	2.371	1,246,246.72	1,795,972.78	481,864.97
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			38,097.0	0.0	38,097.0	1.626	1.789	619,642.84	681,607.14	42,811.68
SUB-TOTAL SCHEDULE C POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE CB POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE MA/MB POWER SALES-JURISD.			37,643.0	0.0	37,643.0	1.665	2.960	626,603.88	1,114,365.64	481,864.97
TOTAL			75,740.0	0.0	75,740.0	1.645	2.371	1,246,246.72	1,795,972.78	524,676.65
DIFFERENCE			61,325.0	0.0	61,325.0	(0.274)	0.213	969,551.35	1,484,898.56	496,677.03
DIFFERENCE %			425.4%	0.0%	425.4%	-14.3%	9.9%	350.4%	477.3%	1773.9%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2020 - DECEMBER 2020

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7) CENTS/KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FROM OTHER UTILITIES	MWH FOR INTER- RUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL \$ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS		23,940.0	0.0	0.0	23,940.0	3.788	3.788	906,840.50
TOTAL		23,940.0	0.0	0.0	23,940.0	3.788	3.788	906,840.50
ACTUAL:								
CITY OF LAKELAND	SCH. - J	800.0	0.0	0.0	800.0	8.900	8.900	71,200.00
DUKE ENERGY FLORIDA	SCH. - J	540,756.0	0.0	0.0	540,756.0	3.371	3.371	18,231,413.67
EDF TRADING	SCH. - J	878.0	0.0	0.0	878.0	3.579	3.579	31,420.00
EXGEN	SCH. - J	28,125.0	0.0	0.0	28,125.0	3.440	3.440	967,446.00
FLA. POWER & LIGHT	SCH. - J	40,828.0	0.0	0.0	40,828.0	4.010	4.010	1,637,271.00
FMPA	SCH. - J	10,994.0	0.0	0.0	10,994.0	3.296	3.296	362,367.29
MACQUARIE ENERGY LLC	SCH. - J	4,022.0	0.0	0.0	4,022.0	3.344	3.344	134,498.00
ORLANDO UTIL. COMM.	SCH. - J	5,469.0	0.0	0.0	5,469.0	4.682	4.682	256,051.00
SOUTHERN COMPANY	SCH. - J	13,149.0	0.0	0.0	13,149.0	4.130	4.130	543,069.00
THE ENERGY AUTHORITY	SCH. - J	8,653.0	0.0	0.0	8,653.0	4.290	4.290	371,252.50
DUKE ENERGY FLORIDA	OATT	10,480.0	0.0	0.0	10,480.0	4.491	4.491	470,607.00
SUB-TOTAL		664,154.0	0.0	0.0	664,154.0	3.475	3.475	23,076,595.46
SUB-TOTAL SCHEDULE D PURCHASED POWER		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL SCHEDULE J PURCHASED POWER		653,674.0	0.0	0.0	653,674.0	3.458	3.458	22,605,988.46
SUB-TOTAL SCHEDULE OATT PURCHASED POWER		10,480.0	0.0	0.0	10,480.0	4.491	4.491	470,607.00
TOTAL		664,154.0	0.0	0.0	664,154.0	3.475	3.475	23,076,595.46
DIFFERENCE		640,214.0	0.0	0.0	640,214.0	(0.313)	(0.313)	22,169,754.96
DIFFERENCE %		2674.2%	0.0%	0.0%	2674.2%	-8.3%	-8.3%	2444.7%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2020 - DECEMBER 2020

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
						CENTS/KWH		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FROM OTHER UTILITIES	MWH FOR INTER- RUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL \$ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.							
	AS AVAIL.	123,937.3	0.0	0.0	123,937.3	2.828	2.828	3,504,445.64
TOTAL		123,937.3	0.0	0.0	123,937.3	2.828	2.828	3,504,445.64
ACTUAL:								
	AS AVAILABLE							
CARGILL MILLPOINT	COGEN.	16,035.0	0.0	0.0	16,035.0	1.769	1.769	283,680.00
CARGILL RIDGEWOOD	COGEN.	12,812.0	0.0	0.0	12,812.0	1.430	1.430	183,154.10
HILLSBOROUGH COUNTY	COGEN.	1.0	0.0	0.0	1.0	1.711	1.711	17.11
IMC-AGRICO-NEW WALES	COGEN.	1,094.0	0.0	0.0	1,094.0	1.845	1.845	20,185.08
IMC-AGRICO-S. PIERCE	COGEN.	103,173.0	0.0	0.0	103,173.0	1.791	1.791	1,848,256.43
McKAY BAY REFUSE	COGEN.	1.0	0.0	0.0	1.0	1.443	1.443	14.43
SUB-TOTAL COGEN		133,116.0	0.0	0.0	133,116.0	1.754	1.754	2,335,307.15
NET METERING		2,254.6	0.0	0.0	2,254.6	2.207	2.207	49,764.41
TOTAL INCL NET METERING		135,370.6	0.0	0.0	135,370.6	1.762	1.762	2,385,071.56
DIFFERENCE		11,433.3	0.0	0.0	11,433.3	(1.066)	(1.066)	(1,119,374.08)
DIFFERENCE %		9.2%	0.0%	0.0%	9.2%	-37.7%	-37.7%	-31.9%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2020 - DECEMBER 2020

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							(A)	(B)	
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	TRANSACTION COSTS CENTS/KWH	TOTAL \$ FOR FUEL ADJUSTMENT (5) X (6)	CENTS PER KWH	TOTAL COST	FUEL SAVINGS (8B)-7
ESTIMATED:									
VARIOUS	Economy	1,799,649.0	0.0	1,799,649.0	2.427	43,677,129.42	2.933	52,777,148.37	9,100,018.95
TOTAL		1,799,649.0	0.0	1,799,649.0	2.427	43,677,129.42	2.933	52,777,148.37	9,100,018.95
ACTUAL:									
CITY OF LAKELAND	SCH. - J	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
DUKE ENERGY FLORIDA	SCH. - J	700,399.0	0.0	700,399.0	3.052	21,378,684.95	3.476	24,342,725.33	2,964,040.38
EDF TRADING	SCH. - J	140.0	0.0	140.0	2.600	3,640.00	2.733	3,826.20	186.20
EXGEN	SCH. - J	2,212.0	0.0	2,212.0	2.758	61,000.00	9.661	213,705.60	152,705.60
FLA. POWER & LIGHT	SCH. - J	1,083,941.0	0.0	1,083,941.0	2.462	26,685,511.57	2.835	30,725,866.39	4,040,354.82
FMPA	SCH. - J	9,360.0	0.0	9,360.0	3.307	309,498.28	3.459	323,738.70	14,240.42
MACQUARIE ENERGY LLC	SCH. - J	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	SCH. - J	9,545.0	0.0	9,545.0	3.127	298,492.50	4.065	387,987.49	89,494.99
SOUTHERN COMPANY	SCH. - J	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	SCH. - J	5,520.0	0.0	5,520.0	3.139	173,280.00	4.391	242,404.80	69,124.80
SUB-TOTAL		1,811,117.0	0.0	1,811,117.0	2.701	48,910,107.30	3.105	56,240,254.51	7,330,147.21
SUB-TOTAL SCHEDULE J ECONOMY PURCHASES									
TOTAL		1,811,117.0	0.0	1,811,117.0	2.701	48,910,107.30	3.105	56,240,254.51	7,330,147.21
DIFFERENCE									
DIFFERENCE		11,468.0	0.0	11,468.0	0.274	5,232,977.88	0.173	3,463,106.14	(1,769,871.74)
DIFFERENCE %									
DIFFERENCE		0.6%	0.0%	0.6%	11.3%	12.0%	5.9%	6.6%	-19.4%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A12

JANUARY 2020 - DECEMBER 2020

REDACTED

CAPACITY COSTS
ACTUAL PURCHASES AND SALES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

CONTRACT	TERM		CONTRACT		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	START	END	TYPE		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	(\$)
SEMINOLE ELECTRIC **	6/1/1992	-----	LT	QF = QUALIFYING FACILITY													
FWPA	12/1/2019 - 2/29/2020		ST	LT = LONG TERM													
FWPA	7/1/2020 - 9/30/2020		ST	ST = SHORT-TERM													
FWPA	12/1/2020 - 2/28/2021		ST	** THREE YEAR NOTICE REQUIRED FOR TERMINATION.													
POU	12/1/2020 - 2/28/2021		ST														
FPL	12/1/2020 - 2/28/2021		ST														

CONTRACT	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	(\$)
SEMINOLE ELECTRIC	9.5	8.8	5.0	10.0	10.5	8.5	7.5	7.6	7.4	8.3	8.0	8.7	
FWPA	88.0	100.0	0.0	0.0	0.0	0.0	74.0	74.0	74.0	0.0	0.0	150.0	
ORLANDO UTILITIES												100.0	
FLORIDA POWER & LIGHT												160.0	

CAPACITY	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
FLORIDA POWER & LIGHT													
DUKE ENERGY FLORIDA													
FWPA													
JACKSONVILLE ELECTRIC AUTHORITY													

SUBTOTAL CAPACITY PURCHASES

SEMINOLE ELECTRIC - D													
CITY OF TALLAHASSEE - MA													
DUKE ENERGY FLORIDA - MA													
FLORIDA POWER & LIGHT - MA													
CITY OF LAKELAND - MA													
ORLANDO UTILITIES - MA													
EXGEN - MA													
THE ENERGY AUTHORITY - MA													
MORGAN STANLEY - MA													
SOUTHERN CO - MA													
NEW SMYRNA BEACH - MA													

SUBTOTAL CAPACITY SALES

TOTAL PURCHASES AND (SALES)	\$ 407,803	\$ 274,777	\$ (75,745)	\$ 611,588	\$ 591,373	\$ 846,816	\$ 763,162	\$ 1,232,628	\$ 941,677	\$ 594,783	\$ 715,642	\$ 1,057,224	\$ 7,951,728
TOTAL CAPACITY	\$ 407,803	\$ 274,777	\$ (75,745)	\$ 611,588	\$ 591,373	\$ 846,816	\$ 763,162	\$ 1,232,628	\$ 941,677	\$ 594,783	\$ 715,642	\$ 1,057,224	\$ 7,951,728

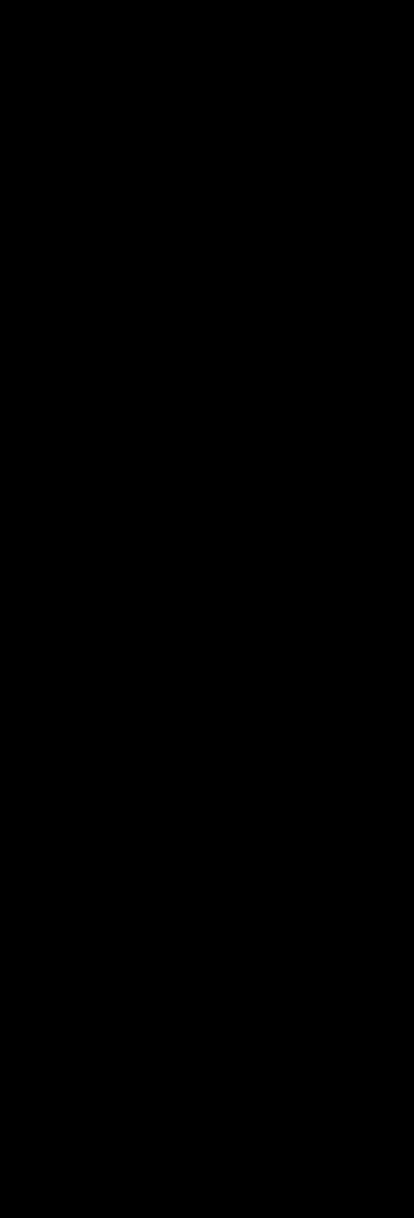


EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 5

CAPITAL PROJECTS APPROVED FOR FUEL CLAUSE RECOVERY

JANUARY 2020 – DECEMBER 2020

**BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020**

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ESTIMATE JUNE	ESTIMATE JULY	ESTIMATE AUGUST	ESTIMATE SEPTEMBER	ESTIMATE OCTOBER	ESTIMATE NOVEMBER	ESTIMATE DECEMBER	TOTAL
1 BEGINNING BALANCE	\$20,910,348	\$20,910,348	\$20,910,348	\$20,910,348	\$20,910,348								\$20,910,348
2 ADD INVESTMENT: Big Bend Unit 3 (Jan 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2a ADD INVESTMENT: Big Bend Unit 4 (May 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2b ADD INVESTMENT: Big Bend Unit 2 (June 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
2c ADD INVESTMENT: Big Bend Unit 1 (November 2015)	-	-	-	-	-	-	-	-	-	-	-	-	-
3 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4 ENDING BALANCE	\$20,910,348	\$20,910,348	\$20,910,348	\$20,910,348	\$20,910,348								\$20,910,348
5													
6													
7 AVERAGE BALANCE	\$20,910,348	\$20,910,348	\$20,910,348	\$20,910,348	\$20,910,348								
8 DEPRECIATION RATE	1.66667%	1.66667%	1.66667%	1.66667%	1.66667%								
9 DEPRECIATION EXPENSE	\$348,506	\$348,506	\$348,506	\$348,506	\$238,475								\$1,632,499
10 LESS RETIREMENTS	-	-	-	-	-								-
11 BEGINNING BALANCE DEPRECIATION	\$19,277,850	\$19,626,355	\$19,974,861	\$20,323,367	\$20,671,873								\$19,277,850
12 ENDING BALANCE DEPRECIATION	\$19,626,355	\$19,974,861	\$20,323,367	\$20,671,873	\$20,910,348								\$20,910,348
13													
14													
15 ENDING NET INVESTMENT	\$1,283,993	\$935,487	\$586,981	\$238,475	-								-
16													
17													
18 AVERAGE INVESTMENT	\$1,458,246	\$1,109,740	\$761,234	\$412,728	\$119,238								
19 ALLOWED EQUITY RETURN	37413%	37413%	37413%	37413%	37413%								
20 EQUITY COMPONENT AFTER-TAX	\$5,456	\$4,152	\$2,848	\$1,544	\$446								\$14,446
21 CONVERSION TO PRE-TAX	1,32830	1,32830	1,32830	1,32830	1,32830								
22 EQUITY COMPONENT PRE-TAX	\$7,247	\$5,515	\$3,783	\$2,051	\$592								\$19,188
23													
24 ALLOWED DEBT RETURN	14474%	14474%	14474%	14474%	14474%								
25 DEBT COMPONENT	\$2,111	\$1,606	\$1,102	\$597	\$173								\$5,589
26 TAX REFORM TRUEUP													
27 TOTAL RETURN	\$9,358	\$7,121	\$4,885	\$2,648	\$765								\$24,777
28 REQUIREMENTS													
29 PRIOR MONTH TRUE-UP													
30 TOTAL DEPRECIATION & RETURN	\$357,864	\$355,827	\$353,391	\$351,154	\$239,240								\$1,657,276
31 ESTIMATED FUEL SAVINGS	\$226,880	\$100,996	\$338,796	\$15,142	\$481,133								\$1,162,948
32 TOTAL DEPRECIATION & RETURN	\$357,864	\$355,827	\$353,391	\$351,154	\$239,240								\$1,657,276
33 NET BENEFIT (COST) TO RATEPAYER	(\$130,984)	(\$254,631)	(\$14,594)	(\$336,012)	\$241,893	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$494,328)

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - MAY USING AN ANNUAL RATE OF 7.7004% (EQUITY 5.8635%, DEBT 1.73699%). RATES ARE BASED ON THE MAY 2019 SURVEILLANCE REPORT
PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 THE RETURN REQUIREMENT FOR JANUARY - DECEMBER IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 24.522%
37 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
January 2020 to June 2020

	(1) Jurisdictional Rate Base Actual May 2019 Capital Structure (\$000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	\$ 1,897,597	31.57%	4.89%	1.5435%
Short Term Debt	211,895	3.52%	2.97%	0.1047%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	94,966	1.58%	2.38%	0.0376%
Common Equity	2,598,065	43.22%	10.25%	4.4297%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,125,550	18.72%	0.00%	0.0000%
Deferred ITC - Weighted Cost	<u>83,633</u>	<u>1.39%</u>	7.98%	<u>0.1110%</u>
Total	<u>\$ 6,011,707</u>	<u>100.00%</u>		<u>6.23%</u>

ITC split between Debt and Equity:

Long Term Debt	\$ 1,897,597	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	<u>2,598,065</u>	Equity - Common	<u>54.00%</u>
Total	<u>\$ 4,495,662</u>	Total	<u>100.00%</u>

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	<u>0.0599%</u>
Weighted Cost	<u>0.1110%</u>

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	<u>0.0599%</u>
	4.4896%
Times Tax Multiplier	1.32830
Total Equity Component	<u>5.9635%</u>

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	<u>0.0511%</u>
Total Debt Component	<u>1.7369%</u>
	<u><u>7.7004%</u></u>

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 1

FUEL AND PURCHASED POWER COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2021 THROUGH DECEMBER 2021

TAMPA ELECTRIC COMPANY

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PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1-A Calculation of Total True-Up	(JAN. 2021 - DEC. 2021)
3	Schedule E1-B Calculation of Estimated True-Up	(")
4	Schedule E2 Cost Recovery Clause Calculation	(")
5-6	Schedule E3 Generating System Comparative Data	(")
7-24	Schedule E4 System Net Generation and Fuel Cost	(")
25-26	Schedule E5 Inventory Analysis	(")
27-28	Schedule E6 Power Sold	(")
29	Schedule E7 Purchased Power	(")
30	Schedule E8 Energy Payment to Qualifying Facilities	(")
31	Schedule E9 Economy Energy Purchases	(")

**TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP FOR
THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021**

SCHEDULE E1-A

1. ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2021 - December 2021 (6 months actual, 6 months estimated)	(\$44,617,507)
2. PROJECTED OVER/UNDER-RECOVERY TRUE-UP INCLUDED IN SEPTEMBER - DECEMBER 2021 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	(\$49,015,848)
3. DIFFERENCE IN 2020 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2021 RATES AND AMOUNT COLLECTED IN 2021 (\$25,479,055 under-recovery less (\$2,123,255) refunded each month January through August 2021)	<u>(\$8,493,015)</u>
4. ACTUAL-ESTIMATED 2021 OVER/(UNDER) RECOVERY (Line 1 - Line 2 + Line 3)	(\$4,094,674)
5. FINAL TRUE-UP (January 2020 - December 2020) (Per True-Up filed April 2, 2021)	<u>3,769,256</u>
6. TOTAL OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2022 (Line 4 + Line 5) To be included in the 12-month projected period January 2022 through December 2022	<u><u>(\$325,418)</u></u>
7. JURISDICTIONAL MWH SALES (Projected January 2022 through December 2022)	19,807,340
8. TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,776,928)	0.0016

TAMPA ELECTRIC COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E1-B

	ACTUAL						ESTIMATED						TOTAL
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	
A. 1. Fuel Cost of System Net Generation	35,046,966	39,125,613	40,884,243	38,039,705	50,080,450	52,697,554	59,789,675	62,349,352	58,680,756	53,390,665	49,881,202	51,183,615	591,149,796
2. Fuel Cost of Power Sold ⁽¹⁾	78,834	203,749	61,837	126,336	199,759	108,640	90,552	93,463	91,001	86,377	97,306	95,893	1,333,746
3. Fuel Cost of Purchased Power	5,133,663	1,197,293	716,669	306,769	1,388,951	862,106	0	0	0	0	0	0	9,605,451
3a. Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
3b. Payments to Qualifying Facilities	65,320	347,074	214,254	50,941	181,888	229,552	183,290	188,490	161,600	152,560	150,110	134,790	2,059,869
4. Energy Cost of Economy Purchases	548,031	2,383,161	3,477,145	3,470,960	9,286,373	9,189,426	11,480,270	11,484,420	10,604,920	11,029,890	2,605,660	112,500	75,672,756
5. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
5a. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
5b. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
6. TOTAL FUEL & NET POWER TRANS.	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,126
⁽¹⁾ Includes Gains													
B. 1. Jurisdictional MWH Sales	1,538,264	1,376,720	1,370,486	1,489,907	1,639,034	1,886,168	1,934,606	1,924,409	2,007,766	1,819,261	1,522,255	1,435,265	19,944,141
2. Non-Jurisdictional MWH Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
3. TOTAL SALES (LINE B1+B2)	1,538,264	1,376,720	1,370,486	1,489,907	1,639,034	1,886,168	1,934,606	1,924,409	2,007,766	1,819,261	1,522,255	1,435,265	19,944,141
4. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	-
C. 1. Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	48,037,811	42,754,413	42,417,459	46,397,644	51,575,423	60,000,677	62,056,327	61,610,667	86,225,188	77,448,347	64,032,223	60,076,100	702,632,279
1a. Jurisdictional Fuel Recovery Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
2. True-up Provision	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	0	0	0	0	(16,986,040)
2a. Mid-Course True Up									(12,253,962)	(12,253,962)	(12,253,962)	(12,253,962)	(49,015,848)
2b. Incentive Provision	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,175)	(2,858,056)
2c. 2019 Optimization Mechanism Gains	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,398)	(1,180,820)
3. FUEL REVENUE APPLICABLE TO PERIOD	45,577,983	40,294,585	39,957,631	43,937,816	49,115,595	57,540,849	59,596,499	59,150,839	73,634,653	64,857,812	51,441,688	47,485,565	632,591,515
4. Total Fuel and Net Power Transactions (Line A6)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,126
5. Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
5a. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	-
5b. Jurisdictional Sales Adjusted for Line Losses	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
5c. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
6. JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
7. Over/(Under) Recovery	4,862,837	(2,554,807)	(5,272,843)	2,195,777	(11,622,308)	(5,329,149)	(11,766,184)	(14,777,960)	4,278,378	371,074	(1,097,978)	(3,849,447)	(44,562,610)
8. Interest Provision	(1,640)	(1,345)	(1,339)	(1,292)	(937)	(1,255)	(5,989)	(13,656)	(13,040)	(8,379)	(4,577)	(1,448)	(54,897)
9. TOTAL ESTIMATED TRUE-UP FOR THE PERIOD													(44,617,507)

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	TOTAL
	Actual			Estimated			Estimated			Estimated			PERIOD
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	
1. Fuel Cost of System Net Generation	35,046,966	39,125,613	40,884,243	38,039,705	50,080,450	52,697,554	59,789,675	62,349,352	58,680,756	53,390,665	49,881,202	51,183,615	591,149,796
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold ⁽¹⁾	78,834	203,749	61,837	126,336	199,759	108,640	90,552	93,463	91,001	86,377	97,306	95,893	1,333,746
4. Fuel Cost of Purchased Power	5,133,663	1,197,293	716,669	306,769	1,388,951	862,106	0	0	0	0	0	0	9,605,451
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	65,320	347,074	214,254	50,941	181,888	229,552	183,290	188,490	161,600	152,560	150,110	134,790	2,059,869
7. Energy Cost of Economy Purchases	548,031	2,383,161	3,477,145	3,470,960	9,286,373	9,189,426	11,480,270	11,484,420	10,604,920	11,029,890	2,605,660	112,500	75,672,757
8. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
9. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
11. TOTAL FUEL & NET POWER TRANSACTIONS	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,127
12. Jurisdictional MWh Sold	1,538,264	1,376,720	1,370,486	1,489,907	1,639,034	1,886,168	1,934,606	1,924,409	2,007,766	1,819,261	1,522,255	1,435,265	19,944,141
13. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	-
14. Jurisdictional Total Fuel & Net Power Transactions (Line 11 * Line 13)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
15. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	-
16. Jurisdictional Sales Adjusted for Line Losses (Line 14 * Line 15)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
17. Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
18. JURISD. TOTAL FUEL & NET PWR. TRANS. (LINE 16+17)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
19. Cost Per kWh Sold (Cents/kWh)	2.6468	3.1124	3.3003	2.8017	3.7057	3.3332	3.6887	3.8416	3.4544	3.5447	3.4514	3.5767	3.3953
20. Optimization Mechanism (Cents/kWh) ⁽²⁾	(0.0064)	(0.0071)	(0.0072)	(0.0066)	(0.0060)	(0.0052)	(0.0051)	(0.0051)	(0.0049)	(0.0054)	(0.0065)	(0.0069)	(0.0060)
21. True-up (Cents/kWh) ⁽²⁾	0.1380	0.1542	0.1549	0.1425	0.1295	0.1126	0.1098	0.1103	0.6103	0.6736	0.8050	0.8538	0.3329
22. Total (Cents/kWh) (Line 19+20+21)	2.7784	3.2595	3.4480	2.9376	3.8292	3.4406	3.7934	3.9468	4.0598	4.2129	4.2499	4.4236	3.7221
23. Revenue Tax Factor	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
24. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	2.7804	3.2619	3.4505	2.9397	3.8320	3.4431	3.7962	3.9497	4.0627	4.2159	4.2530	4.4268	3.7248
25. GPIF Adjusted for Taxes (Cents/kWh) ⁽²⁾	0.0155	0.0173	0.0174	0.0160	0.0145	0.0126	0.0123	0.0124	0.0119	0.0131	0.0156	0.0166	0.0146
26. TOTAL RECOVERY FACTOR (LINE 24+25)	2.7959	3.2792	3.4679	2.9557	3.8465	3.4557	3.8085	3.9621	4.0746	4.2290	4.2686	4.4434	3.7394
27. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	2.796	3.279	3.468	2.956	3.846	3.456	3.808	3.962	4.075	4.229	4.269	4.443	3.739

⁽¹⁾ Includes Gains

⁽²⁾ Based on Jurisdictional Sales Only

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E3

	ACTUAL					
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FUEL COST OF SYSTEM NET GENERATION (\$)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	17,031	87,245	17,929	57,370	25,842	51,354
3. COAL	2,523,735	7,498,306	4,799,736	2,803,672	3,851,041	6,065,132
4. NATURAL GAS	32,506,200	31,540,062	36,066,578	35,178,663	46,203,567	46,581,068
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL (\$)	35,046,966	39,125,613	40,884,243	38,039,705	50,080,450	52,697,554
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	178	101	115	96	51	85
10. COAL	83,163	196,789	126,454	63,348	108,168	178,944
11. NATURAL GAS	1,151,915	1,023,714	1,230,975	1,277,518	1,393,547	1,403,874
12. SOLAR	82,335	86,652	117,281	133,120	150,867	110,572
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	1,317,591	1,307,256	1,474,825	1,474,082	1,652,633	1,693,475
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	115	588	121	408	184	365
17. COAL (TON)	36,182	90,829	58,946	32,825	49,854	86,003
18. NATURAL GAS (MCF)	9,027,318	8,122,935	9,620,165	10,225,351	11,410,833	10,516,609
19. SOLAR	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	669	3,427	704	2,376	1,070	2,127
23. COAL	833,193	2,074,833	1,360,675	764,197	1,152,870	1,982,976
24. NATURAL GAS	9,244,078	8,329,906	9,831,194	10,430,648	11,687,186	10,778,573
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	10,077,940	10,408,166	11,192,573	11,197,222	12,841,126	12,763,677
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.01	0.01	0.01	0.01	0.00	0.01
30. COAL	6.31	15.05	8.57	4.29	6.55	10.56
31. NATURAL GAS	87.43	78.31	83.47	86.67	84.32	82.90
32. SOLAR	6.25	6.63	7.95	9.03	9.13	6.53
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT						
35. HEAVY OIL (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL (\$/BBL)	148.10	148.38	148.17	140.61	140.45	140.70
37. COAL (\$/TON)	69.75	82.55	81.43	85.41	77.25	70.52
38. NATURAL GAS (\$/MCF)	3.60	3.88	3.75	3.44	4.05	4.43
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU (\$/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	25.46	25.46	25.47	24.15	24.15	24.14
43. COAL	3.03	3.61	3.53	3.67	3.34	3.06
44. NATURAL GAS	3.52	3.79	3.67	3.37	3.95	4.32
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL (\$/MMBTU)	3.48	3.76	3.65	3.40	3.90	4.13
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	3,758	33,931	6,124	24,752	20,980	25,024
50. COAL	10,019	10,543	10,760	12,063	10,658	11,082
51. NATURAL GAS	8,025	8,137	7,987	8,165	8,387	7,678
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	7,649	7,962	7,589	7,596	7,770	7,537
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	9.57	86.38	15.59	59.76	50.67	60.42
57. COAL	3.03	3.81	3.80	4.43	3.56	3.39
58. NATURAL GAS	2.82	3.08	2.93	2.75	3.32	3.32
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	2.66	2.99	2.77	2.58	3.03	3.11

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

SCHEDULE E3

Estimated							
	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	TOTAL
FUEL COST OF SYSTEM NET GENERATION (\$)							
1. HEAVY OIL	0	0	0	0	0	0	0
2. LIGHT OIL	93,217	92,828	92,445	92,069	45,941	91,513	764,784
3. COAL	5,248,735	5,533,990	4,972,764	1,109,083	952,197	5,503,061	50,861,452
4. NATURAL GAS	54,447,723	56,722,534	53,615,547	52,189,513	48,883,064	45,589,041	539,523,560
5. SOLAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL (\$)	59,789,675	62,349,352	58,680,756	53,390,665	49,881,202	51,183,615	591,149,796
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	0	0	0	0	0	0	0
9. LIGHT OIL	300	300	300	300	150	300	2,276
10. COAL	140,060	155,160	137,900	28,490	25,870	158,610	1,402,956
11. NATURAL GAS	1,507,380	1,530,630	1,445,730	1,395,900	1,258,570	1,249,980	15,869,733
12. SOLAR	148,910	144,090	124,210	123,740	97,710	110,870	1,430,357
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	1,796,650	1,830,180	1,708,140	1,548,430	1,382,300	1,519,760	18,705,322
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	0	0	0	0	0	0	0
16. LIGHT OIL (BBL)	666	666	666	666	333	666	5,444
17. COAL (TON)	74,450	80,160	72,930	15,640	13,950	80,950	692,719
18. NATURAL GAS (MCF)	10,954,655	11,289,625	10,723,105	10,542,335	9,995,638	8,986,635	121,415,204
19. SOLAR	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	0	0	0	0	0	0	0
22. LIGHT OIL	3,900	3,900	3,900	3,900	1,950	3,900	31,824
23. COAL	1,675,180	1,803,630	1,640,900	351,850	313,830	1,821,380	15,775,515
24. NATURAL GAS	11,236,060	11,577,820	10,986,420	10,809,590	10,229,600	9,227,110	124,368,185
25. SOLAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	12,915,140	13,385,350	12,631,220	11,165,340	10,545,380	11,052,390	140,175,523
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.01	0.02	0.01
30. COAL	7.79	8.48	8.07	1.84	1.87	10.43	7.50
31. NATURAL GAS	83.90	83.63	84.64	90.15	91.05	82.25	84.84
32. SOLAR	8.29	7.87	7.27	7.99	7.07	7.30	7.65
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT							
35. HEAVY OIL (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL (\$/BBL)	139.97	139.38	138.81	138.24	137.96	137.41	140.48
37. COAL (\$/TON)	70.50	69.04	68.19	70.91	68.26	67.98	73.42
38. NATURAL GAS (\$/MCF)	4.97	5.02	5.00	4.95	4.89	5.07	4.44
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU (\$/MMBTU)							
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	23.90	23.80	23.70	23.61	23.56	23.46	24.03
43. COAL	3.13	3.07	3.03	3.15	3.03	3.02	3.22
44. NATURAL GAS	4.85	4.90	4.88	4.83	4.78	4.94	4.34
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL (\$/MMBTU)	4.63	4.66	4.65	4.78	4.73	4.63	4.22
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	0	0	0	0	0	0	0
49. LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000	13,982
50. COAL	11,960	11,624	11,899	12,350	12,131	11,483	11,244
51. NATURAL GAS	7,454	7,564	7,599	7,744	8,128	7,382	7,837
52. SOLAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	7,188	7,314	7,395	7,211	7,629	7,272	7,494
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	31.07	30.94	30.82	30.69	30.63	30.50	33.60
57. COAL	3.75	3.57	3.61	3.89	3.68	3.47	3.63
58. NATURAL GAS	3.61	3.71	3.71	3.74	3.88	3.65	3.40
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	3.33	3.41	3.44	3.45	3.61	3.37	3.16

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2021

SCHEDULE A4
PAGE 1 OF 2

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	201	16.9	-	47.6	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	2,263	15.8	-	38.1	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	155	13.9	-	33.2	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	9,507	18.2	-	45.4	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	9,399	17.0	-	42.5	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	9,153	16.6	-	41.1	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	7,677	17.0	-	42.8	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	6,954	17.1	-	42.3	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	4,448	16.0	-	38.1	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	6,137	16.7	-	41.3	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	9,893	17.8	-	42.9	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	9,643	17.4	-	43.7	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	6,905	15.5	-	38.1	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	82,335	17.0	-	40.5	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL	350	38,985	15.0	34.6	43.3	12,208	GAS	464,311	1,025,000	475,918.6	1,672,133	4.29	3.60
B.B.#3 (COAL)	400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	355	139,271	52.7	78.7	52.7	-	GAS	1,630,571	1,025,000	1,671,335.9	5,872,214	4.22	3.60
BIG BEND #3 TOTAL	355	139,271	52.7	78.7	52.7	12,001	-	-	-	1,671,335.9	5,872,214	4.22	-
B.B.#4 (COAL)	432	84,738	26.4	60.1	57.9	-	COAL	36,182	23,027,843	833,193.4	2,523,735	2.98	69.75
B.B.#4 (GAS)	160	30,218	25.4	60.1	74.4	-	GAS	294,876	1,025,000	302,247.5	1,061,942	3.51	3.60
BIG BEND #4 TOTAL	432	114,956	35.8	60.1	49.8	9,877	-	-	-	1,135,440.9	3,585,677	3.12	-
B.B. IGNITION	-	-	-	-	-	-	GAS	8,709	1,025,000	8,927.0	31,365	-	3.60
BIG BEND CT #4 TOTAL	61	18	0.0	89.4	18.7	67,356	GAS	1,183	1,025,000	1,212.4	4,260	23.67	3.60
BIG BEND STATION TOTAL	1,198	293,230	32.9	59.7	32.9	11,199	-	-	-	3,283,907.9	11,165,649	3.81	-
POLK #1 GASIFIER	220	(1,575)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	180	7,130	4.5	73.4	45.1	11,531	GAS	80,213	1,025,000	82,218.0	288,872	3.02	3.60
POLK #1 ST	50	2,420	5.4	73.4	57.2	-	-	-	-	-	-	-	-
POLK #1 TOTAL	230	7,975	4.7	73.4	47.3	10,308	-	-	-	82,218.0	288,872	3.62	-
POLK #2 ST DUCT FIRING	480	15,997	4.5	-	31.2	8,400	GAS	131,098	1,025,000	134,375.1	472,125	2.95	3.60
POLK #2 ST W/O DUCT FIRING	341	184,554	72.7	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	480	200,551	56.2	99.6	31.2	-	GAS	-	-	134,375.1	472,125	0.24	-
POLK #2 CT (GAS)	180	83,115	62.1	100.0	78.9	10,336	GAS	838,102	1,025,000	859,054.8	3,018,277	3.63	3.60
POLK #2 CT (OIL)	187	151	0.1	100.0	26.9	3,758	LGT.OIL	97	5,829,600	566.7	14,365	9.51	148.09
POLK #2 TOTAL	180	83,266	62.2	100.0	78.9	10,324	-	-	-	859,621.5	3,032,642	3.64	-
POLK #3 CT (GAS)	180	67,245	50.2	100.0	78.7	12,897	GAS	846,130	1,025,000	867,283.4	3,047,188	4.53	3.60
POLK #3 CT (OIL)	187	27	0.0	100.0	10.5	3,758	LGT.OIL	18	5,829,600	102.3	2,666	9.87	148.11
POLK #3 TOTAL	180	67,272	50.2	100.0	78.7	12,894	-	-	-	867,385.7	3,049,854	4.53	-
POLK #4 TOTAL	180	94,597	70.6	99.7	80.8	9,591	GAS	885,172	1,025,000	907,301.4	3,187,790	3.37	3.60
POLK #5 TOTAL	180	92,660	69.2	100.0	80.9	10,602	GAS	958,395	1,025,000	982,355.3	3,451,491	3.72	3.60
POLK #2 CC TOTAL	1,200	538,346	60.3	99.8	60.5	6,968	GAS	-	-	3,751,039.0	13,193,902	2.45	-
POLK STATION TOTAL	1,430	546,321	51.4	95.6	51.5	7,016	-	-	-	3,833,256.9	13,482,774	2.47	-

SCHEDULE A4
PAGE 2 OF 2

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	243	0	0.0	81.0	0.0	-		-	-	-	-	-	-
BAYSIDE CT1A	183	0	0.0	81.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE CT1B	183	0	0.0	81.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE CT1C	183	0	0.0	80.7	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE UNIT 1 TOTAL	792	0	0.0	81.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE ST 2	315	140,820	60.1	97.8	60.1	-		-	-	-	-	-	-
BAYSIDE CT2A	(3) 183	84,419	62.0	100.0	65.6	11,433	GAS	941,876	1,025,000	965,423.9	3,390,660	4.02	3.60
BAYSIDE CT2B	(3) 183	73,077	53.7	100.0	65.5	11,767	GAS	839,222	1,025,000	860,203.3	3,021,115	4.13	3.60
BAYSIDE CT2C	(3) 183	46,034	33.8	96.5	65.6	11,735	GAS	527,312	1,025,000	540,495.6	1,898,271	4.12	3.60
BAYSIDE CT2D	(3) 183	49,686	36.5	97.9	66.0	11,602	GAS	562,656	1,025,000	576,723.6	2,025,505	4.08	3.60
BAYSIDE UNIT 2 TOTAL	1,047	394,036	50.6	98.4	50.6	7,466	GAS	2,871,066	1,025,000	2,942,846.4	10,335,551	2.62	3.60
BAYSIDE UNIT 3 TOTAL	61	0	0.0	98.7	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE UNIT 4 TOTAL	61	703	1.6	100.0	88.4	10,876	GAS	7,459	1,025,000	7,645.7	26,863	3.82	3.60
BAYSIDE UNIT 5 TOTAL	61	672	1.5	100.0	88.3	10,448	GAS	6,848	1,025,000	7,018.8	24,660	3.67	3.60
BAYSIDE UNIT 6 TOTAL	61	294	0.7	100.0	84.1	11,094	GAS	3,185	1,025,000	3,264.4	11,469	3.90	3.60
BAYSIDE STATION TOTAL	2,083	395,705	25.5	91.9	25.5	7,479	GAS	2,888,558	1,025,000	2,960,775.3	10,398,543	2.63	3.60
SYSTEM	5,363	1,317,591	33.0	84.8	35.6	7,648	-	-	-	10,077,940.1	35,046,966	2.66	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

Footnotes:
(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) Consists of prior month adjustments, details on Schedule A5, page 2.

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2021

SCHEDULE A4
PAGE 1 OF 2

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	217	19.5	-	52.6	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	2,582	19.2	-	45.5	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	164	15.7	-	36.3	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	8,177	16.8	-	48.2	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	10,354	20.0	-	48.5	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	9,931	19.2	-	46.6	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	8,318	19.7	-	48.5	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	7,584	19.9	-	48.7	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	4,804	18.5	-	42.1	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	6,769	19.7	-	47.7	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	10,287	19.8	-	46.1	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	10,301	19.9	-	47.6	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	7,164	17.2	-	41.9	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	86,652	19.1	-	43.6	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL	350	109,228	46.4	100.0	46.4	12,243	GAS	1,303,381	464,311	1,337,268.7	5,060,820	4.63	3.88
B.B.#3 (COAL)	400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	355	24,732	10.4	99.2	58.7	-	GAS	275,602	1,630,572	282,767.8	1,070,119	4.33	3.88
BIG BEND #3 TOTAL	355	24,732	10.4	99.2	58.7	11,433	-	-	-	282,767.8	1,070,119	4.33	-
B.B.#4 (COAL)	432	198,395	66.0	98.4	77.6	-	COAL	90,829	36,182	2,074,832.8	7,513,270	3.79	82.72
B.B.#4 (GAS)	160	14,071	12.6	98.4	91.6	-	GAS	145,377	294,876	149,157.2	564,477	4.01	3.88
BIG BEND #4 TOTAL	432	212,466	70.7	98.4	75.3	10,468	-	-	-	2,223,990.0	8,077,747	3.80	-
B.B. IGNITION	-	-	-	-	-	-	GAS	4,118	8,709	4,225.0	15,989	-	3.88
BIG BEND CT #4 TOTAL	61	812	1.9	100.0	81.4	14,234	GAS	11,265	1,183	11,557.7	43,740	5.39	3.88
BIG BEND STATION TOTAL	1,198	347,238	43.1	99.2	43.1	11,104	-	-	-	3,855,584.2	14,268,415	4.11	-
POLK #1 GASIFIER	220	(1,606)	-	-	-	-	COAL	-	-	-	(14,964)	0.93	-
POLK #1 CT (GAS)	180	6,714	4.6	99.9	48.3	13,123	GAS	85,870	80,213	88,103.0	333,421	3.69	3.88
POLK #1 ST	50	2,324	5.7	99.9	63.6	-	-	-	-	-	-	-	-
POLK #1 TOTAL	230	7,432	4.8	99.9	50.9	11,856	-	-	-	88,103.0	318,457	4.28	-
POLK #2 ST DUCT FIRING	480	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
POLK #2 ST W/O DUCT FIRING	341	(616)	0.0	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	480	(616)	(0.2)	67.9	0.0	-	GAS	-	-	0.0	0	0.00	-
POLK #2 CT (GAS)	180	4,615	3.8	94.8	60.5	12,570	GAS	56,540	838,102	58,009.7	219,534	4.76	3.88
POLK #2 CT (OIL)	187	76	0.1	94.8	21.5	34,083	LGT.OIL	443	97	2,584.2	65,730	86.49	148.37
POLK #2 TOTAL	180	4,691	3.9	94.8	60.5	12,917	-	-	-	60,593.8	285,264	6.08	-
POLK #3 CT (GAS)	180	4,424	3.7	94.9	60.6	12,737	GAS	54,911	846,130	56,338.8	213,211	4.82	3.88
POLK #3 CT (OIL)	187	25	0.0	94.9	19.4	34,083	LGT.OIL	145	18	842.7	21,515	86.06	148.38
POLK #3 TOTAL	180	4,449	3.7	94.9	60.6	12,856	-	-	-	57,181.5	234,726	5.28	-
POLK #4 TOTAL	180	2,187	1.8	100.0	56.5	13,289	GAS	28,324	885,172	29,060.9	109,980	5.03	3.88
POLK #5 TOTAL	180	3,200	2.7	100.0	66.2	12,223	GAS	38,120	958,395	39,110.7	148,012	4.63	3.88
POLK #2 CC TOTAL	1,200	13,911	1.7	85.6	26.9	13,368	GAS	-	-	185,946.9	777,982	5.59	-
POLK STATION TOTAL	1,430	21,343	2.2	87.9	23.5	12,841	-	-	-	274,049.9	1,096,439	5.14	-

SCHEDULE A4
PAGE 2 OF 2

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	243	123,939	75.9	97.5	76.5	-		-	-	-	-	-	-
BAYSIDE CT1A	183	79,230	64.4	100.0	71.9	11,384	GAS	879,113	0	901,970.1	3,413,455	4.31	3.88
BAYSIDE CT1B	183	80,910	65.8	100.0	71.9	11,376	GAS	897,097	0	920,421.1	3,483,284	4.31	3.88
BAYSIDE CT1C	183	72,538	59.0	91.7	71.6	11,125	GAS	786,527	0	806,976.4	3,053,958	4.21	3.88
BAYSIDE UNIT 1 TOTAL	792	356,617	67.0	97.3	67.5	7,373	GAS	2,562,737	0	2,629,367.6	9,950,697	2.79	3.88
BAYSIDE ST 2	315	170,426	80.5	99.6	80.5	-		-	-	-	-	-	-
BAYSIDE CT2A	183	82,529	64.8	100.0	73.3	11,036	GAS	887,737	941,593	910,817.8	3,446,940	4.18	3.88
BAYSIDE CT2B	183	87,360	71.0	100.0	72.7	11,331	GAS	964,767	838,938	989,850.8	3,746,036	4.29	3.88
BAYSIDE CT2C	183	75,733	61.6	98.4	73.1	11,306	GAS	834,501	527,028	856,198.2	3,240,235	4.28	3.88
BAYSIDE CT2D	183	77,017	62.6	100.0	72.7	11,256	GAS	844,922	562,373	866,889.8	3,280,697	4.26	3.88
BAYSIDE UNIT 2 TOTAL	1,047	493,065	70.1	99.6	70.1	7,349	GAS	3,531,927	2,869,932	3,623,756.6	13,713,908	2.78	3.88
BAYSIDE UNIT 3 TOTAL	61	174	0.4	100.0	73.1	11,152	GAS	1,886	0	1,935.4	7,325	4.21	3.88
BAYSIDE UNIT 4 TOTAL	61	313	0.8	100.0	84.8	10,826	GAS	3,306	7,459	3,392.5	12,839	4.10	3.88
BAYSIDE UNIT 5 TOTAL	61	1,087	2.7	98.8	84.7	10,732	GAS	11,366	6,848	11,661.1	44,131	4.06	3.88
BAYSIDE UNIT 6 TOTAL	61	767	1.9	98.5	83.5	10,983	GAS	8,205	3,185	8,418.5	31,859	4.15	3.88
BAYSIDE STATION TOTAL	2,083	852,023	60.9	98.7	60.9	7,369	GAS	6,119,427	2,887,424	6,278,531.7	23,760,759	2.79	3.88
SYSTEM	5,363	1,307,256	35.0	95.5	52.4	7,962	-	-	-	10,408,165.8	39,125,613	2.99	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

CC = COMBINED CYCLE
ST = STEAM TURBINE

Footnotes:

- ⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ Consists of fixed costs and aerial survey adjustment.

⁽⁴⁾ Polk's portion of the aerial survey adjustment

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2021

SCHEDULE A4
PAGE 1 OF 2

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	291	24.5	-	70.5	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	3,760	26.2	-	66.3	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	227	20.4	-	50.3	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	5,883	11.3	-	34.7	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	14,705	26.7	-	68.8	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	14,189	25.7	-	66.5	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	11,883	26.3	-	69.3	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	10,626	26.1	-	68.3	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	6,919	24.9	-	60.7	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	9,440	25.7	-	66.6	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	15,790	28.4	-	70.7	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	14,229	25.8	-	65.8	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	9,339	21.0	-	54.6	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	117,281	24.2	-	59.0	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL	350	57,278	22.0	79.0	46.4	12,683	GAS	709,430	1,024,000	726,456.7	2,659,698	4.64	3.75
B.B.#3 (COAL)	400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	355	40,858	15.5	100.0	57.6	-	GAS	480,042	1,024,000	491,563.0	1,799,706	4.40	3.75
BIG BEND #3 TOTAL	355	40,858	15.5	100.0	57.6	12,031	-	-	-	491,563.0	1,799,706	4.40	-
B.B.#4 (COAL)	432	128,065	39.9	86.5	66.3	-	COAL	58,946	23,083,410	1,360,674.7	4,799,736	3.75	81.43
B.B.#4 (GAS)	160	31,366	26.4	86.5	95.2	-	GAS	330,596	1,024,000	338,530.3	1,239,424	3.95	3.75
BIG BEND #4 TOTAL	432	159,431	49.7	86.5	57.4	10,658	-	-	-	1,699,205.0	6,039,160	3.79	-
B.B. IGNITION	-	-	-	-	-	-	GAS	19,390	1,024,000	19,855.3	72,694	-	3.75
BIG BEND CT #4 TOTAL	61	820	1.8	100.0	77.5	14,205	GAS	11,375	1,024,000	11,647.9	42,645	5.20	3.75
BIG BEND STATION TOTAL	1,198	258,387	29.0	89.0	33.6	11,335	-	-	-	2,928,872.6	10,613,903	4.11	-
POLK #1 GASIFIER	220	(1,611)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	180	34,663	25.1	90.9	54.2	12,609	GAS	426,804	1,024,000	437,047.4	1,600,114	3.24	3.75
POLK #1 ST	50	14,719	38.3	95.5	84.1	-	-	-	-	-	-	-	-
POLK #1 TOTAL	230	47,771	27.9	91.9	60.5	9,149	-	-	-	437,047.4	1,600,114	3.35	-
POLK #2 ST DUCT FIRING	480	7,379	2.1	-	0.0	8,400	GAS	60,533	1,024,000	61,985.7	226,941	3.08	3.75
POLK #2 ST W/O DUCT FIRING	341	104,827	41.4	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	480	112,206	31.5	53.3	0.0	-	GAS	-	-	61,985.7	226,941	0.20	-
POLK #2 CT (GAS)	180	58,498	43.7	99.9	75.3	11,390	GAS	650,701	1,024,000	666,317.3	2,439,515	4.17	3.75
POLK #2 CT (OIL)	187	48	0.0	99.9	21.7	6,127	LGT.OIL	50	5,829,600	291.2	7,409	15.44	148.18
POLK #2 TOTAL	180	58,546	43.8	99.9	75.3	11,386	-	-	-	666,608.5	2,446,924	4.18	-
POLK #3 CT (GAS)	180	60,672	45.4	100.0	76.6	11,392	GAS	674,957	1,024,000	691,156.4	2,530,456	4.17	3.75
POLK #3 CT (OIL)	187	67	0.0	100.0	26.4	6,127	LGT.OIL	71	5,829,600	413.0	10,520	15.70	148.17
POLK #3 TOTAL	180	60,739	45.4	100.0	76.6	11,386	-	-	-	691,569.4	2,540,976	4.18	-
POLK #4 TOTAL	180	33,906	25.4	70.6	76.8	11,211	GAS	371,211	1,024,000	380,120.6	1,391,694	4.10	3.75
POLK #5 TOTAL	180	52,408	39.2	100.0	78.4	11,091	GAS	567,629	1,024,000	581,251.6	2,128,073	4.06	3.75
POLK #2 CC TOTAL	1,200	317,805	35.6	76.9	59.3	7,494	GAS	-	-	2,381,535.8	8,734,608	2.75	-
POLK STATION TOTAL	1,430	365,576	34.4	79.3	57.3	7,710	-	-	-	2,818,583.2	10,334,722	2.83	-

(3)

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2021

SCHEDULE A4
PAGE 2 OF 2

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	243	98,363	54.5	68.7	55.8	-		-	-	-	-	-	-
BAYSIDE CT1A	183	43,961	32.3	45.1	71.7	11,409	GAS	489,792	1,024,000	501,546.6	1,836,260	4.18	3.75
BAYSIDE CT1B	183	65,315	48.0	72.5	68.9	11,564	GAS	737,599	1,024,000	755,301.2	2,765,303	4.23	3.75
BAYSIDE CT1C	183	73,555	54.1	98.3	69.0	11,283	GAS	810,462	1,024,000	829,913.5	3,038,471	4.13	3.75
BAYSIDE UNIT 1 TOTAL	792	281,194	47.7	71.0	49.0	7,421	GAS	2,037,853	1,024,000	2,086,761.3	7,640,034	2.72	3.75
BAYSIDE ST 2	315	156,959	67.1	97.3	67.1	-		-	-	-	-	-	-
BAYSIDE CT2A	183	76,481	56.2	89.0	69.6	11,233	GAS	838,988	1,024,000	859,123.9	3,145,417	4.11	3.75
BAYSIDE CT2B	183	89,654	65.9	100.0	70.0	11,464	GAS	1,003,676	1,024,000	1,027,764.4	3,762,843	4.20	3.75
BAYSIDE CT2C	183	66,623	49.0	100.0	71.2	11,413	GAS	742,534	1,024,000	760,354.8	2,783,805	4.18	3.75
BAYSIDE CT2D	183	59,777	44.0	100.0	71.2	11,361	GAS	663,210	1,024,000	679,126.8	2,486,413	4.16	3.75
BAYSIDE UNIT 2 TOTAL	1,047	449,494	57.7	97.3	57.8	7,400	GAS	3,248,408	1,024,000	3,326,369.9	12,178,478	2.71	3.75
BAYSIDE UNIT 3 TOTAL	61	485	1.1	92.9	87.0	10,818	GAS	5,128	1,024,000	5,251.0	19,225	3.96	3.75
BAYSIDE UNIT 4 TOTAL	61	1,197	2.6	100.0	87.4	10,728	GAS	12,536	1,024,000	12,836.8	46,998	3.93	3.75
BAYSIDE UNIT 5 TOTAL	61	597	1.3	100.0	83.9	12,091	GAS	7,047	1,024,000	7,216.3	26,420	4.43	3.75
BAYSIDE UNIT 6 TOTAL	61	614	1.4	100.0	87.0	10,878	GAS	6,525	1,024,000	6,681.7	24,463	3.98	3.75
BAYSIDE STATION TOTAL	2,083	733,581	47.3	87.4	47.4	7,423	GAS	5,317,497	1,024,000	5,445,117.0	19,935,618	2.72	3.75
SYSTEM	5,363	1,474,825	35.8	85.4	46.7	7,589	-	-	-	11,192,572.8	40,884,243	2.77	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

Footnotes:
⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ Consists of prior month adjustments, details on Schedule A5, page 2.

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2021

SCHEDULE A4
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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	298	25.9	-	55.8	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	4,092	29.4	-	59.2	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	205	19.0	-	45.9	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	15,220	30.2	-	61.5	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	14,921	27.9	-	57.0	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	15,635	29.2	-	59.6	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	12,914	29.5	-	60.5	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	11,625	29.5	-	60.4	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	7,552	28.0	-	55.6	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	10,028	28.2	-	58.0	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	15,571	29.0	-	59.1	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	14,061	26.3	-	54.2	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	10,998	25.5	-	52.2	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	133,120	28.3	-	56.2	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL	340	71,829	29.3	72.0	41.0	13,106	GAS	921,110	1,022,000	941,374.8	3,168,931	4.41	3.44
B.B.#3 (COAL)	395	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	345	114,843	46.2	81.5	56.8	-	GAS	1,362,779	1,022,000	1,392,760.3	4,688,420	4.08	3.44
BIG BEND #3 TOTAL	345	114,843	46.2	81.5	56.8	12,128	-	-	-	1,392,760.3	4,688,420	4.08	-
B.B.#4 (COAL)	422	64,334	21.2	33.2	65.7	-	COAL	32,825	23,280,954	764,197.3	2,803,672	4.36	85.41
B.B.#4 (GAS)	155	14,274	12.8	33.2	29.3	-	GAS	168,486	1,022,000	172,192.2	579,647	4.06	3.44
BIG BEND #4 TOTAL	422	78,608	25.9	33.2	59.3	11,912	-	-	-	936,389.5	3,383,319	4.30	-
B.B. IGNITION	-	-	-	-	-	-	GAS	19,238	1,022,000	19,661.5	66,186	-	3.44
BIG BEND CT #4 TOTAL	56	95	0.2	100.0	53.3	26,726	GAS	2,484	1,022,000	2,539.0	8,547	9.00	3.44
BIG BEND STATION TOTAL	1,163	265,375	31.7	62.1	38.9	12,336	-	-	-	3,273,063.6	11,315,403	4.26	-
POLK #1 GASIFIER	220	(986)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	152	33,353	29.8	87.1	68.8	12,157	GAS	396,736	1,022,000	405,464.5	1,364,907	2.91	3.44
POLK #1 ST	50	13,617	37.0	94.1	88.3	-	-	-	-	-	-	-	-
POLK #1 TOTAL	202	45,984	31.6	88.9	72.9	8,818	-	-	-	405,464.5	1,364,907	2.97	-
POLK #2 ST DUCT FIRING	461	7,295	2.2	-	16.2	8,400	GAS	59,962	1,022,000	61,281.5	206,291	2.83	3.44
POLK #2 ST W/O DUCT FIRING	322	162,245	70.0	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	461	169,540	51.1	78.2	16.2	-	GAS	-	-	61,281.5	206,291	0.12	-
POLK #2 CT (GAS)	150	91,776	85.0	100.0	94.0	11,079	GAS	994,933	1,022,000	1,016,822.0	3,422,907	3.73	3.44
POLK #2 CT (OIL)	159	44	0.0	100.0	30.6	24,789	LGT.OIL	186	5,829,600	1,086.0	26,154	59.44	140.61
POLK #2 TOTAL	150	91,820	85.0	100.0	94.0	11,086	-	-	-	1,017,908.0	3,449,061	3.76	-
POLK #3 CT (GAS)	150	92,448	85.7	100.0	92.9	11,167	GAS	1,010,179	1,022,000	1,032,403.3	3,475,358	3.76	3.44
POLK #3 CT (OIL)	159	52	0.0	100.0	36.4	24,789	LGT.OIL	222	5,829,600	1,290.2	31,216	60.03	140.61
POLK #3 TOTAL	150	92,500	85.7	100.0	92.9	11,175	-	-	-	1,033,693.5	3,506,574	3.79	-
POLK #4 TOTAL	150	12,791	11.8	15.1	95.4	10,963	GAS	137,216	1,022,000	140,234.8	472,069	3.69	3.44
POLK #5 TOTAL	150	87,564	81.1	89.9	95.3	10,841	GAS	928,870	1,022,000	949,304.9	3,195,626	3.65	3.44
POLK #2 CC TOTAL	1,061	454,215	59.5	77.1	59.5	7,050	GAS	-	-	3,202,422.7	10,829,621	2.38	-
POLK STATION TOTAL	1,263	500,199	55.0	78.9	55.0	7,213	-	-	-	3,607,887.2	12,194,528	2.44	-

SCHEDULE A4
PAGE 2 OF 2

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	233	90,023	53.7	89.2	54.3	-		-	-	-	-	-	-
BAYSIDE CT1A	156	52,268	46.5	94.8	75.0	11,878	GAS	607,474	1,022,000	620,838.2	2,089,916	4.00	3.44
BAYSIDE CT1B	156	62,842	56.0	100.0	76.8	11,766	GAS	723,473	1,022,000	739,389.6	2,488,992	3.96	3.44
BAYSIDE CT1C	156	46,882	41.7	76.0	77.8	11,429	GAS	524,269	1,022,000	535,803.0	1,803,662	3.85	3.44
BAYSIDE UNIT 1 TOTAL	701	252,015	49.9	89.9	50.5	7,524	GAS	1,855,216	1,022,000	1,896,030.8	6,382,570	2.53	3.44
BAYSIDE ST 2	305	113,993	51.9	96.6	51.9	-		-	-	-	-	-	-
BAYSIDE CT2A	156	86,458	77.0	100.0	77.0	11,446	GAS	968,341	1,022,000	989,643.3	3,331,418	3.85	3.44
BAYSIDE CT2B	156	54,392	48.4	85.6	77.4	11,636	GAS	619,294	1,022,000	632,918.8	2,130,581	3.92	3.44
BAYSIDE CT2C	156	38,762	34.5	100.0	79.0	11,624	GAS	440,888	1,022,000	450,587.6	1,516,803	3.91	3.44
BAYSIDE CT2D	156	28,466	25.3	100.0	77.9	11,668	GAS	324,999	1,022,000	332,148.7	1,118,105	3.93	3.44
BAYSIDE UNIT 2 TOTAL	929	322,071	48.2	96.5	48.2	7,468	GAS	2,353,522	1,022,000	2,405,298.5	8,096,907	2.51	3.44
BAYSIDE UNIT 3 TOTAL	56	187	0.5	90.4	82.0	11,385	GAS	2,082	1,022,000	2,128.3	7,164	3.83	3.44
BAYSIDE UNIT 4 TOTAL	56	395	1.0	76.5	86.3	11,345	GAS	4,389	1,022,000	4,485.4	15,099	3.82	3.44
BAYSIDE UNIT 5 TOTAL	56	328	0.8	77.8	80.6	11,604	GAS	3,725	1,022,000	3,806.9	12,815	3.91	3.44
BAYSIDE UNIT 6 TOTAL	56	392	1.0	84.5	85.1	11,544	GAS	4,424	1,022,000	4,520.9	15,219	3.88	3.44
BAYSIDE STATION TOTAL	1,854	575,388	43.1	92.3	43.1	7,501	GAS	4,223,358	1,022,000	4,316,270.7	14,529,774	2.53	3.44
SYSTEM	4,932	1,474,082	38.2	80.1	46.6	7,596	-	-	-	11,197,221.6	38,039,705	2.58	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

Footnotes:
(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	331	27.8	-	86.6	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	4,486	31.2	-	93.0	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	197	17.7	-	49.2	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	16,634	31.9	-	94.9	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	17,352	31.4	-	93.5	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	18,267	33.0	-	98.0	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	14,552	32.2	-	95.4	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	12,934	31.7	-	93.7	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	8,562	30.8	-	86.7	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	10,264	27.9	-	92.3	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	17,972	32.3	-	93.3	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	16,157	29.2	-	86.6	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	13,159	29.6	-	90.9	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	150,867	27.9	-	92.3	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND 5 CT	(3)	(32)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND 6 CT	(3)	(111)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #1 CC TOTAL	0	(143)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	-
BIG BEND #2 TOTAL	340	102,472	40.5	64.7	40.8	12,919	GAS	1,291,516	1,025,000	1,323,803.7	5,229,472	5.10	4.05
B.B.#3 (COAL)	395	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	345	134,509	52.4	81.2	52.4	-	GAS	1,618,416	1,025,000	1,658,876.9	6,553,124	4.87	4.05
BIG BEND #3 TOTAL	345	134,509	52.4	81.2	52.4	12,333	-	-	-	1,658,876.9	6,553,124	4.87	-
B.B.#4 (COAL)	422	108,630	34.6	57.1	46.2	-	COAL	49,854	23,124,927	1,152,870.1	3,851,041	3.55	77.25
B.B.#4 (GAS)	155	43,225	37.5	57.1	60.2	-	GAS	455,517	1,025,000	466,904.8	1,844,432	4.27	4.05
BIG BEND #4 TOTAL	422	151,855	48.4	57.1	61.0	10,667	-	-	-	1,619,774.9	5,695,473	3.75	-
B.B. IGNITION	-	-	-	-	-	-	GAS	8,701	1,025,000	8,918.9	35,233	-	4.05
BIG BEND CT #4 TOTAL	56	107	0.3	100.0	57.0	20,008	GAS	2,089	0	2,140.9	8,457	7.90	4.05
BIG BEND STATION TOTAL	1,163	388,800	45.0	68.5	45.0	11,843	-	-	-	4,604,596.3	17,521,759	4.51	-
POLK #1 GASIFIER	220	(462)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	152	48,460	42.6	58.4	72.9	11,878	GAS	561,554	1,025,000	575,593.1	2,273,787	3.33	4.05
POLK #1 ST	50	19,824	52.9	58.4	90.7	-	-	-	-	-	-	-	-
POLK #1 TOTAL	202	67,822	45.1	58.4	77.3	8,487	-	-	-	575,593.1	2,273,787	3.35	-
POLK #2 ST DUCT FIRING	461	6,253	1.8	-	18.9	8,400	GAS	51,240	1,025,000	52,521.1	207,476	3.32	4.05
POLK #2 ST W/O DUCT FIRING	322	181,577	75.8	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	461	187,830	54.8	85.3	18.9	-	GAS	-	-	52,521.1	207,476	0.11	-
POLK #2 CT (GAS)	150	50,657	45.4	60.1	89.7	11,241	GAS	555,543	1,025,000	569,431.9	2,249,448	4.44	4.05
POLK #2 CT (OIL)	159	21	0.0	60.1	14.7	20,685	LGT.OIL	76	5,829,600	444.3	10,674	50.83	140.45
POLK #2 TOTAL	150	50,678	45.4	60.1	89.7	11,245	-	-	-	569,876.2	2,260,122	4.46	-
POLK #3 CT (GAS)	150	87,268	78.2	93.8	89.7	11,297	GAS	961,783	1,025,000	985,827.7	3,894,353	4.46	4.05
POLK #3 CT (OIL)	159	30	0.0	93.8	23.9	20,685	LGT.OIL	108	5,829,600	626.1	15,168	50.56	140.44
POLK #3 TOTAL	150	87,298	78.2	93.8	89.7	11,300	-	-	-	986,453.8	3,909,521	4.48	-
POLK #4 TOTAL	150	93,103	83.4	100.0	92.7	10,930	GAS	992,822	1,025,000	1,017,642.8	4,020,033	4.32	4.05
POLK #5 TOTAL	150	85,068	76.2	93.6	92.0	10,947	GAS	908,537	1,025,000	931,250.4	3,678,754	4.32	4.05
POLK #2 CC TOTAL	1,061	503,977	63.8	86.2	64.1	7,059	GAS	-	-	3,557,744.3	14,075,906	2.79	-
POLK STATION TOTAL	1,263	571,799	60.9	81.8	61.1	7,229	-	-	-	4,133,337.4	16,349,693	2.86	-

SCHEDULE A4
PAGE 2 OF 2

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	233	85,157	49.1	89.6	54.4	-		-	-	-	-	-	-
BAYSIDE CT1A	156	44,631	38.5	97.0	74.1	11,939	GAS	519,843	1,025,000	532,838.8	2,104,894	4.72	4.05
BAYSIDE CT1B	156	55,178	47.5	98.1	74.6	11,895	GAS	640,336	1,025,000	656,344.5	2,592,782	4.70	4.05
BAYSIDE CT1C	156	53,072	45.7	100.0	73.7	11,647	GAS	603,031	1,025,000	618,106.4	2,441,730	4.60	4.05
BAYSIDE UNIT 1 TOTAL	701	238,038	45.6	95.5	50.6	7,592	GAS	1,763,210	1,025,000	1,807,289.8	7,139,406	3.00	4.05
BAYSIDE ST 2	305	107,322	47.3	83.6	47.3	-		-	-	-	-	-	-
BAYSIDE CT2A	156	55,425	47.8	78.1	75.0	11,571	GAS	625,708	1,025,000	641,350.4	2,533,551	4.57	4.05
BAYSIDE CT2B	156	50,770	43.7	78.6	75.4	11,696	GAS	579,317	1,025,000	593,799.6	2,345,709	4.62	4.05
BAYSIDE CT2C	156	46,338	39.9	100.0	75.8	11,798	GAS	533,341	1,025,000	546,674.7	2,159,550	4.66	4.05
BAYSIDE CT2D	156	43,058	37.1	78.4	73.9	11,864	GAS	498,382	1,025,000	510,841.4	2,017,997	4.69	4.05
BAYSIDE UNIT 2 TOTAL	929	302,913	43.8	83.7	43.8	7,569	GAS	2,236,747	1,025,000	2,292,666.1	9,056,807	2.99	4.05
BAYSIDE UNIT 3 TOTAL	56	0	0.0	100.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE UNIT 4 TOTAL	56	138	0.3	98.9	64.2	14,964	GAS	2,022	1,025,000	2,072.6	8,187	5.93	4.05
BAYSIDE UNIT 5 TOTAL	56	78	0.2	99.0	65.0	15,018	GAS	1,136	1,025,000	1,163.9	4,598	5.89	4.05
BAYSIDE UNIT 6 TOTAL	56	0	0.0	97.9	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE STATION TOTAL	1,854	541,167	39.2	90.0	39.2	7,582	GAS	4,003,115	1,025,000	4,103,192.4	16,208,998	3.00	4.05
SYSTEM	4,932	1,652,633	45.0	81.7	49.3	7,770	-	-	-	12,841,126.1	50,080,450	3.03	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

Footnotes:
(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) Station Service
CC = COMBINED CYCLE
ST = STEAM TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	265	23.0	-	49.0	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	3,150	22.7	-	41.4	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	183	16.9	-	31.4	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	12,162	24.1	-	47.0	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	13,403	25.1	-	48.3	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	13,403	25.1	-	47.7	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	10,766	24.6	-	47.6	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	9,321	23.6	-	46.0	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	6,254	23.2	-	41.7	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	8,239	23.2	-	45.6	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	13,137	24.4	-	44.6	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	10,731	20.1	-	39.0	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	9,558	22.2	-	44.8	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	110,572	23.2	-	45.6	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND 5 CT	(3) 0	(89)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND 6 CT	(3) 0	(136)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #1 CC TOTAL	0	(225)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	-
BIG BEND #2 TOTAL	340	24,423	10.0	69.3	42.5	12,733	GAS	303,398	1,025,000	310,983.2	1,342,417	5.50	4.42
B.B.#3 (COAL)	395	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	345	99,833	40.2	60.0	54.4	-	GAS	1,186,154	1,025,000	1,215,807.8	5,246,297	5.26	4.42
BIG BEND #3 TOTAL	345	99,833	40.2	60.0	54.4	12,178	-	-	-	1,215,807.8	5,246,297	5.26	-
B.B.#4 (COAL)	422	180,558	59.4	82.2	60.6	-	COAL	86,003	23,057,060	1,982,976.3	6,065,132	3.36	70.52
B.B.#4 (GAS)	155	2,564	2.3	82.2	35.2	-	GAS	27,823	1,025,000	28,518.2	124,319	4.85	4.47
BIG BEND #4 TOTAL	422	183,122	60.3	82.2	60.3	10,984	-	-	-	2,011,494.5	6,189,451	3.38	-
B.B. IGNITION	-	-	-	-	-	-	GAS	928	1,025,000	951.7	1,730	-	1.86
BIG BEND CT #4 TOTAL	56	250	0.6	100.0	68.7	16,217	GAS	3,955	0	4,054.2	17,493	7.00	4.42
BIG BEND STATION TOTAL	1,163	307,403	36.7	72.7	36.7	11,523	-	-	-	3,542,339.6	12,797,388	4.16	-
POLK #1 GASIFIER	220	(1,614)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	152	(354)	(0.9)	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
POLK #1 ST	50	(599)	(4.5)	0.0	0.0	-	-	-	-	-	-	-	-
POLK #1 TOTAL	202	(2,567)	(1.8)	0.0	0.0	0	-	-	-	0.0	0	0.00	-
POLK #2 ST DUCT FIRING	461	8,287	2.5	-	20.6	8,400	GAS	67,910	1,025,000	69,607.6	300,334	3.62	4.42
POLK #2 ST W/O DUCT FIRING	322	210,062	90.6	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	461	218,349	65.8	100.0	20.6	-	GAS	-	-	69,607.6	300,334	0.14	-
POLK #2 CT (GAS)	150	84,607	78.3	99.8	91.3	11,256	GAS	929,075	1,025,000	952,301.7	4,108,874	4.86	4.42
POLK #2 CT (OIL)	159	19	0.0	99.8	33.5	24,975	LGT.OIL	80	5,829,600	466.2	11,256	59.24	140.70
POLK #2 TOTAL	150	84,626	78.4	99.8	91.3	11,259	-	-	-	952,767.9	4,120,130	4.87	-
POLK #3 CT (GAS)	150	73,447	68.1	77.9	92.7	11,175	GAS	800,762	1,025,000	820,780.9	3,541,405	4.82	4.42
POLK #3 CT (OIL)	159	66	0.1	77.9	26.6	24,975	LGT.OIL	285	5,829,600	1,660.8	40,098	60.75	140.69
POLK #3 TOTAL	150	73,513	68.1	77.9	92.7	11,188	-	-	-	822,441.8	3,581,503	4.87	-
POLK #4 TOTAL	150	99,391	92.0	99.1	92.9	10,971	GAS	1,063,869	1,025,000	1,090,465.6	4,705,007	4.73	4.42
POLK #5 TOTAL	150	99,578	92.2	100.0	93.4	10,929	GAS	1,061,707	1,025,000	1,088,250.2	4,695,448	4.72	4.42
POLK #2 CC TOTAL	1,061	575,457	75.3	96.7	75.3	6,992	GAS	-	-	4,023,533.0	17,402,422	3.02	-
POLK STATION TOTAL	1,263	572,890	63.0	81.2	63.0	7,023	-	-	-	4,023,533.0	17,402,422	3.04	-

SCHEDULE A4
PAGE 2 OF 2

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	233	94,726	56.5	83.8	66.8	-		-	-	-	-	-	-
BAYSIDE CT1A	156	55,953	49.8	91.8	75.1	11,825	GAS	645,523	1,025,000	661,661.4	2,863,891	5.12	4.44
BAYSIDE CT1B	156	59,406	52.9	97.3	76.0	11,769	GAS	682,117	1,025,000	699,169.7	3,026,242	5.09	4.44
BAYSIDE CT1C	156	51,369	45.7	95.2	74.6	11,545	GAS	578,581	1,025,000	593,045.4	2,566,900	5.00	4.44
BAYSIDE UNIT 1 TOTAL	701	261,454	51.8	91.1	61.3	7,473	GAS	1,906,221	1,025,000	1,953,876.5	8,457,033	3.23	4.44
BAYSIDE ST 2	305	158,473	72.2	94.8	72.2	-		-	-	-	-	-	-
BAYSIDE CT2A	156	81,371	72.4	100.0	77.6	11,333	GAS	899,664	1,025,000	922,155.5	3,991,398	4.91	4.44
BAYSIDE CT2B	156	81,747	72.8	100.0	77.9	11,475	GAS	915,190	1,025,000	938,069.4	4,060,279	4.97	4.44
BAYSIDE CT2C	156	57,327	51.0	79.3	77.9	11,585	GAS	647,928	1,025,000	664,126.4	2,874,562	5.01	4.44
BAYSIDE CT2D	156	61,738	55.0	100.0	77.7	11,543	GAS	695,287	1,025,000	712,668.9	3,084,670	5.00	4.44
BAYSIDE UNIT 2 TOTAL	929	440,656	65.9	94.8	65.9	7,346	GAS	3,158,068	1,025,000	3,237,020.2	14,010,909	3.18	4.44
BAYSIDE UNIT 3 TOTAL	56	0	0.0	100.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE UNIT 4 TOTAL	56	62	0.2	100.0	74.1	12,765	GAS	775	1,025,000	794.0	3,426	5.53	4.42
BAYSIDE UNIT 5 TOTAL	56	295	0.7	100.0	31.3	14,493	GAS	4,174	1,025,000	4,278.1	18,459	6.26	4.42
BAYSIDE UNIT 6 TOTAL	56	143	0.4	100.0	77.2	12,868	GAS	1,790	1,025,000	1,835.0	7,917	5.54	4.42
BAYSIDE STATION TOTAL	1,854	702,610	52.6	94.0	52.6	7,398	GAS	5,071,028	1,025,000	5,197,803.8	22,497,744	3.20	4.44
SYSTEM	4,932	1,693,474	47.7	84.5	50.7	7,537	-	-	-	12,763,676.5	52,697,554	3.11	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

Footnotes:
(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) Station Service

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	290	2.0	-	2.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,280	383.5	-	383.5	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,340	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,950	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,310	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,640	30.2	-	30.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,450	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,490	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,810	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	16,390	29.6	-	29.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,360	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,310	32.2	-	32.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL ⁽³⁾	651.9	148,910	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	11,190	4.4	82.2	33.6	14,349	GAS	156,200	1,027,977	160,570.0	776,358	6.94	4.97
19. B.B.#3 (GAS)	345	38,440	15.0	-	-	-	GAS	445,550	1,027,988	458,020.0	2,214,509	5.76	4.97
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	38,440	15.0	83.9	54.6	11,915	-	-	-	458,020.0	2,214,509	5.76	-
22. B.B.#4 (GAS)	155	7,370	6.4	-	-	-	GAS	85,770	1,027,865	88,160.0	426,301	5.78	4.97
23. B.B.#4 (COAL)	422	140,060	44.6	-	-	-	COAL	74,450	22,500,739	1,675,180.0	5,248,735	3.75	70.50
24. BIG BEND #4 TOTAL	422	147,430	47.0	89.7	51.1	11,961	-	-	-	1,763,340.0	5,675,036	3.85	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	24,630	1,028,015	25,320.0	122,418	-	4.97
26. B.B.C.T.#4 TOTAL	56	420	1.0	98.3	46.9	14,833	GAS	6,070	1,026,359	6,230.0	30,170	7.18	4.97
27. B.B.C.T.#5 TOTAL	330	0	0.0	93.4	0.0	0	GAS	0	0	0.0	0	0.00	0.00
28. B.B.C.T.#6 TOTAL	330	0	0.0	97.1	0.0	0	GAS	0	0	0.0	0	0.00	0.00
29. BIG BEND STATION TOTAL	1,823	197,480	14.6	89.5	50.2	12,093	-	-	-	2,388,160.0	8,818,491	4.47	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	29,810	20.9	-	89.2	8,871	GAS	257,240	1,027,989	264,440.0	1,278,555	4.29	4.97
32. POLK #1 TOTAL	220	29,810	18.2	0.0	89.2	8,871	-	-	-	264,440.0	1,278,555	4.29	-
33. POLK #2 ST DUCT FIRING	120	6,950	7.8	-	69.8	8,273	GAS	55,930	1,028,071	57,500.0	277,988	4.00	4.97
34. POLK #2 ST W/O DUCT FIRING	341	585,290	-	-	-	-	-	3,934,435	1,028,005	4,044,620.0	19,555,250	3.34	4.97
35. POLK #2 ST TOTAL	461	592,240	172.7	-	158.2	6,926	GAS	-	-	4,102,120.0	19,833,238	3.35	-
36. POLK #2 CT (GAS)	150	500	0.4	-	83.3	11,300	GAS	5,500	1,027,273	5,650.0	27,337	5.47	4.97
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,609	31.07	139.97
38. POLK #2 TOTAL ⁽⁴⁾	150	650	0.6	-	85.6	11,692	-	-	-	7,600.0	73,946	11.38	-
39. POLK #3 CT (GAS)	150	480	0.4	-	80.0	11,542	GAS	5,390	1,027,829	5,540.0	26,790	5.58	4.97
40. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,608	31.07	139.96
41. POLK #3 TOTAL ⁽⁴⁾	150	630	0.6	-	83.0	11,889	-	-	-	7,490.0	73,398	11.65	-
42. POLK #4 CT (GAS) TOTAL ⁽⁴⁾	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
43. POLK #5 CT (GAS) TOTAL ⁽⁴⁾	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
44. POLK #2 CC TOTAL	1,061	593,520	75.2	0.0	157.3	6,937	-	-	-	4,117,210.0	19,980,582	3.37	-
45. POLK STATION TOTAL	1,281	623,330	65.4	0.0	145.4	7,029	-	-	-	4,381,650.0	21,259,137	3.41	-
46. BAYSIDE #1	720	404,140	75.4	97.3	78.2	7,325	GAS	2,879,690	1,028,000	2,960,320.0	14,312,871	3.54	4.97
47. BAYSIDE #2	954	421,280	59.4	97.4	61.0	7,507	GAS	3,076,440	1,027,997	3,162,570.0	15,290,773	3.63	4.97
48. BAYSIDE #3	56	280	0.7	98.6	45.5	15,357	GAS	4,180	1,028,708	4,300.0	20,776	7.42	4.97
49. BAYSIDE #4	56	220	0.5	98.6	39.3	16,318	GAS	3,480	1,031,609	3,590.0	17,297	7.86	4.97
50. BAYSIDE #5	56	730	1.8	98.6	50.1	14,274	GAS	10,140	1,027,613	10,420.0	50,389	6.90	4.97
51. BAYSIDE #6	56	280	0.7	98.6	50.0	14,750	GAS	4,010	1,029,925	4,130.0	19,931	7.12	4.97
52. BAYSIDE STATION TOTAL	1,898	826,930	58.6	97.5	68.3	7,431	GAS	6,977,940	1,028,001	6,146,330.0	29,712,047	3.59	4.97

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	270	1.9	-	1.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,200	376.3	-	376.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	15,770	30.2	-	30.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,350	29.6	-	29.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	16,730	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,170	29.1	-	29.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,040	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,360	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,430	28.4	-	28.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	15,880	28.7	-	28.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	16,780	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	13,820	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL	⁽³⁾ 651.9	144,090	29.7	-	29.7	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	10,610	4.2	82.2	32.5	14,530	GAS	149,960	1,028,007	154,160.0	753,445	7.10	5.02
19. B.B.#3 (GAS)	345	41,450	16.1	-	-	-	GAS	480,520	1,027,991	493,970.0	2,414,280	5.82	5.02
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	41,450	16.1	83.9	54.6	11,917	-	-	-	493,970.0	2,414,280	5.82	-
22. B.B.#4 (GAS)	155	8,170	7.1	-	-	-	GAS	92,340	1,028,049	94,930.0	463,944	5.68	5.02
23. B.B.#4 (COAL)	422	155,160	49.4	-	-	-	COAL	80,160	22,500,374	1,803,630.0	5,533,990	3.57	69.04
24. BIG BEND #4 TOTAL	422	163,330	52.0	89.7	56.6	11,624	-	-	-	1,898,560.0	5,997,934	3.67	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	27,140	1,028,003	27,900.0	136,360	-	5.02
26. B.B.C.T.#4 TOTAL	56	360	0.9	98.3	53.6	13,861	GAS	4,850	1,028,866	4,990.0	24,368	6.77	5.02
27. B.B.C.T.#5 TOTAL	330	57,940	23.6	93.4	24.1	9,341	GAS	526,460	1,028,017	541,210.0	2,645,096	4.57	5.02
28. B.B.C.T.#6 TOTAL	330	21,820	8.9	97.1	9.1	9,536	GAS	202,410	1,028,012	208,080.0	1,016,970	4.66	5.02
29. BIG BEND STATION TOTAL	1,823	295,510	21.8	89.5	33.6	11,170	-	-	-	3,300,970.0	12,988,453	4.40	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	19,700	13.8	-	87.0	8,926	GAS	171,080	1,027,882	175,850.0	859,558	4.36	5.02
32. POLK #1 TOTAL	220	19,700	12.0	0.0	87.0	8,926	-	-	-	175,850.0	859,558	4.36	-
33. POLK #2 ST DUCT FIRING	120	4,110	4.6	-	62.3	8,273	GAS	33,070	1,028,122	34,000.0	166,154	4.04	5.02
34. POLK #2 ST W/O DUCT FIRING	341	575,450	-	-	-	-	-	3,867,825	1,028,004	3,976,140.0	19,433,137	3.38	5.02
35. POLK #2 ST TOTAL	461	579,560	169.0	-	160.8	6,919	GAS	-	-	4,010,140.0	19,599,291	3.38	-
36. POLK #2 CT (GAS)	150	1,240	1.1	-	82.7	11,347	GAS	13,690	1,027,757	14,070.0	68,783	5.55	5.02
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,414	30.94	139.38
38. POLK #2 TOTAL	⁽⁴⁾ 150	1,390	1.2	-	83.8	11,525	-	-	-	16,020.0	115,197	8.29	-
39. POLK #3 CT (GAS)	150	580	0.5	-	96.7	10,914	GAS	6,160	1,027,597	6,330.0	30,950	5.34	5.02
40. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,414	30.94	139.38
41. POLK #3 TOTAL	⁽⁴⁾ 150	730	0.7	-	96.2	11,342	-	-	-	8,280.0	77,364	10.60	-
42. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	430	0.4	-	95.6	10,814	GAS	4,520	1,028,761	4,650.0	22,710	5.28	5.02
43. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	290	0.3	-	96.7	11,241	GAS	3,170	1,028,391	3,260.0	15,927	5.49	5.02
44. POLK #2 CC TOTAL	1,061	582,400	73.8	0.0	158.9	6,941	-	-	-	4,042,350.0	19,830,489	3.40	-
45. POLK STATION TOTAL	1,281	602,100	63.2	0.0	149.7	7,006	-	-	-	4,218,200.0	20,690,047	3.44	-
46. BAYSIDE #1	720	386,100	72.1	97.3	76.7	7,331	GAS	2,753,440	1,027,998	2,830,530.0	13,834,126	3.58	5.02
47. BAYSIDE #2	954	400,690	56.5	97.4	59.2	7,516	GAS	2,929,450	1,027,998	3,011,470.0	14,718,454	3.67	5.02
48. BAYSIDE #3	56	330	0.8	98.6	49.1	14,758	GAS	4,750	1,025,263	4,870.0	23,865	7.23	5.02
49. BAYSIDE #4	56	240	0.6	98.6	47.6	14,750	GAS	3,450	1,026,087	3,540.0	17,334	7.22	5.02
50. BAYSIDE #5	56	690	1.7	98.6	53.6	13,841	GAS	9,290	1,027,987	9,550.0	46,676	6.76	5.02
51. BAYSIDE #6	56	430	1.0	98.6	51.2	14,465	GAS	6,050	1,028,099	6,220.0	30,397	7.07	5.02
52. BAYSIDE STATION TOTAL	1,898	788,480	55.8	97.5	66.7	7,440	GAS	5,706,430	1,027,995	5,866,180.0	28,670,852	3.64	5.02

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	230	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,480	322.2	-	322.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,710	27.2	-	27.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,200	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,400	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,450	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,470	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,760	25.1	-	25.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	9,070	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	13,730	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,420	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	12,030	27.9	-	27.9	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL	⁽³⁾ 651.9	124,210	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	21,020	8.6	82.2	32.2	14,584	GAS	298,200	1,028,035	306,560.0	1,491,000	7.09	5.00
19. B.B.#3 (GAS)	345	27,000	10.9	-	-	-	GAS	313,880	1,027,972	322,660.0	1,569,400	5.81	5.00
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	27,000	10.9	75.5	54.0	11,950	-	-	-	322,660.0	1,569,400	5.81	-
22. B.B.#4 (GAS)	155	7,260	6.5	-	-	-	GAS	84,010	1,027,973	86,360.0	420,050	5.79	5.00
23. B.B.#4 (COAL)	422	137,900	45.4	-	-	-	COAL	72,930	22,499,657	1,640,900.0	4,972,764	3.61	68.19
24. BIG BEND #4 TOTAL	422	145,160	47.8	89.7	52.0	11,899	-	-	-	1,727,260.0	5,392,814	3.72	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	35,900	1,028,134	36,910.0	179,500	-	5.00
26. B.B.C.T.#4 TOTAL	56	70	0.2	98.3	25.0	20,429	GAS	1,390	1,028,777	1,430.0	6,950	9.93	5.00
27. B.B.C.T.#5 TOTAL	330	32,140	13.5	93.4	13.8	9,203	GAS	287,750	1,027,976	295,800.0	1,438,751	4.48	5.00
28. B.B.C.T.#6 TOTAL	330	42,220	17.8	97.1	18.1	9,236	GAS	379,330	1,027,970	389,940.0	1,896,651	4.49	5.00
29. BIG BEND STATION TOTAL	1,823	267,610	20.4	87.9	31.1	11,373	-	-	-	3,043,650.0	11,975,067	4.47	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	22,200	16.1	-	88.3	8,910	GAS	192,410	1,028,013	197,800.0	962,050	4.33	5.00
32. POLK #1 TOTAL	220	22,200	14.0	0.0	88.3	8,910	-	-	-	197,800.0	962,050	4.33	-
33. POLK #2 ST DUCT FIRING	120	3,660	4.2	-	58.7	8,265	GAS	29,430	1,027,863	30,250.0	147,150	4.02	5.00
34. POLK #2 ST W/O DUCT FIRING	341	544,460	-	-	-	-	-	3,661,355	1,028,005	3,763,890.0	18,306,782	3.36	5.00
35. POLK #2 ST TOTAL	461	548,120	165.1	-	156.2	6,922	GAS	-	-	3,794,140.0	18,453,932	3.37	-
36. POLK #2 CT (GAS)	150	1,380	1.3	-	92.0	10,899	GAS	14,630	1,028,025	15,040.0	73,151	5.30	5.00
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,223	30.82	138.81
38. POLK #2 TOTAL	⁽⁴⁾ 150	1,530	1.4	-	92.2	11,105	-	-	-	16,990.0	119,374	7.80	-
39. POLK #3 CT (GAS)	150	1,390	1.3	-	92.7	10,942	GAS	14,800	1,027,703	15,210.0	74,000	5.32	5.00
40. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,222	30.81	138.80
41. POLK #3 TOTAL	⁽⁴⁾ 150	1,540	1.4	-	92.8	11,143	-	-	-	17,160.0	120,222	7.81	-
42. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	880	0.8	-	97.8	10,693	GAS	9,150	1,028,415	9,410.0	45,750	5.20	5.00
43. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	1,010	0.9	-	96.2	10,871	GAS	10,680	1,028,090	10,980.0	53,400	5.29	5.00
44. POLK #2 CC TOTAL	1,061	553,080	72.4	0.0	153.5	6,959	-	-	-	3,848,680.0	18,792,678	3.40	-
45. POLK STATION TOTAL	1,281	575,280	62.4	0.0	144.3	7,034	-	-	-	4,046,480.0	19,754,728	3.43	-
46. BAYSIDE #1	720	374,200	72.2	97.3	74.2	7,347	GAS	2,674,490	1,027,998	2,749,370.0	13,372,455	3.57	5.00
47. BAYSIDE #2	954	364,550	53.1	97.4	54.7	7,572	GAS	2,685,260	1,028,005	2,760,460.0	13,426,306	3.68	5.00
48. BAYSIDE #3	56	510	1.3	98.6	56.9	13,882	GAS	6,890	1,027,576	7,080.0	34,450	6.75	5.00
49. BAYSIDE #4	56	240	0.6	98.6	47.6	14,208	GAS	3,320	1,027,108	3,410.0	16,600	6.92	5.00
50. BAYSIDE #5	56	830	2.1	98.6	57.0	13,422	GAS	10,850	1,026,728	11,140.0	54,250	6.54	5.00
51. BAYSIDE #6	56	710	1.8	98.6	57.6	13,563	GAS	9,380	1,026,652	9,630.0	46,900	6.61	5.00
52. BAYSIDE STATION TOTAL	1,898	741,040	54.2	97.5	63.1	7,477	GAS	5,390,190	1,027,995	5,541,090.0	26,950,961	3.64	5.00

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	220	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,600	322.6	-	322.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,550	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,050	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,040	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,300	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,340	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	7,140	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,970	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	14,260	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,090	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,890	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL	⁽³⁾ 651.9	123,740	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	12,190	4.8	82.2	32.6	14,510	GAS	172,070	1,027,954	176,880.0	851,827	6.99	4.95
19. B.B.#3 (GAS)	345	27,200	10.6	-	-	-	GAS	315,660	1,028,005	324,500.0	1,562,666	5.75	4.95
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	27,200	10.6	64.9	54.4	11,930	-	-	-	324,500.0	1,562,666	5.75	-
22. B.B.#4 (GAS)	155	1,500	1.3	-	-	-	GAS	18,010	1,028,318	18,520.0	89,158	5.94	4.95
23. B.B.#4 (COAL)	422	28,490	9.1	-	-	-	COAL	15,640	22,496,803	351,850.0	1,109,083	3.89	70.91
24. BIG BEND #4 TOTAL	422	29,990	9.6	20.3	45.8	12,350	-	-	-	370,370.0	1,198,241	4.00	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	27,140	1,028,003	27,900.0	134,356	-	4.95
26. B.B.C.T.#4 TOTAL	56	220	0.5	98.3	32.7	16,727	GAS	3,570	1,030,812	3,680.0	17,673	8.03	4.95
27. B.B.C.T.#5 TOTAL	330	112,500	45.8	93.4	46.7	9,201	GAS	1,006,930	1,027,996	1,035,120.0	4,984,777	4.43	4.95
28. B.B.C.T.#6 TOTAL	330	78,720	32.1	97.1	32.7	9,201	GAS	704,580	1,027,988	724,300.0	3,488,002	4.43	4.95
29. BIG BEND STATION TOTAL	1,823	260,820	19.2	69.8	41.1	10,102	-	-	-	2,634,850.0	12,237,542	4.69	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	26,840	18.8	-	86.3	8,918	GAS	232,830	1,028,003	239,350.0	1,152,618	4.29	4.95
32. POLK #1 TOTAL	220	26,840	16.4	0.0	86.3	8,918	-	-	-	239,350.0	1,152,618	4.29	-
33. POLK #2 ST DUCT FIRING	120	2,530	2.8	-	49.0	8,277	GAS	20,370	1,027,982	20,940.0	100,841	3.99	4.95
34. POLK #2 ST W/O DUCT FIRING	341	505,400	-	-	-	-	-	3,403,045	1,028,003	3,498,340.0	16,846,672	3.33	4.95
35. POLK #2 ST TOTAL	461	507,930	148.1	-	142.5	6,929	GAS	-	-	3,519,280.0	16,947,513	3.34	-
36. POLK #2 CT (GAS)	150	1,440	1.3	-	80.0	11,451	GAS	16,050	1,027,414	16,490.0	79,455	5.52	4.95
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,034	30.69	138.24
38. POLK #2 TOTAL	⁽⁴⁾ 150	1,590	1.4	-	81.2	11,597	-	-	-	18,440.0	125,489	7.89	-
39. POLK #3 CT (GAS)	150	1,440	1.3	-	80.0	11,451	GAS	16,050	1,027,414	16,490.0	79,455	5.52	4.95
40. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,035	30.69	138.24
41. POLK #3 TOTAL	⁽⁴⁾ 150	1,590	1.4	-	81.2	11,597	-	-	-	18,440.0	125,490	7.89	-
42. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
43. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	910	0.8	-	86.7	11,209	GAS	9,930	1,027,190	10,200.0	49,158	5.40	4.95
44. POLK #2 CC TOTAL	1,061	512,020	64.9	0.0	140.1	6,965	-	-	-	3,566,360.0	17,247,650	3.37	-
45. POLK STATION TOTAL	1,281	538,860	56.5	0.0	131.1	7,063	-	-	-	3,805,710.0	18,400,268	3.41	-
46. BAYSIDE #1	720	300,570	56.1	84.7	66.6	7,401	GAS	2,164,030	1,027,999	2,224,620.0	10,712,966	3.56	4.95
47. BAYSIDE #2	954	323,770	45.6	91.1	46.9	7,685	GAS	2,420,380	1,028,000	2,488,150.0	11,982,018	3.70	4.95
48. BAYSIDE #3	56	110	0.3	98.6	39.3	16,364	GAS	1,750	1,028,571	1,800.0	8,663	7.88	4.95
49. BAYSIDE #4	56	90	0.2	98.6	32.1	18,111	GAS	1,580	1,031,646	1,630.0	7,822	8.69	4.95
50. BAYSIDE #5	56	280	0.7	98.6	35.7	17,357	GAS	4,730	1,027,484	4,860.0	23,416	8.36	4.95
51. BAYSIDE #6	56	190	0.5	98.6	28.3	19,579	GAS	3,630	1,024,793	3,720.0	17,970	9.46	4.95
52. BAYSIDE STATION TOTAL	1,898	625,010	44.3	89.6	54.7	7,560	GAS	4,596,100	1,027,998	4,724,780.0	22,752,855	3.64	4.95

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2021

SCHEDULE E4

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	180	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,970	274.6	-	274.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	10,130	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,500	19.6	-	19.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,030	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,420	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,720	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,040	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,700	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	11,780	22.0	-	22.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,070	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,900	20.6	-	20.6	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL	⁽³⁾ 651.9	97,710	20.8	-	20.8	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	21,640	8.8	82.2	40.5	13,391	GAS	281,890	1,027,990	289,780.0	1,378,566	6.37	4.89
19. B.B.#3 (GAS)	345	53,180	21.4	-	-	-	GAS	617,500	1,028,000	634,790.0	3,019,847	5.68	4.89
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	53,180	21.4	83.9	54.3	11,937	-	-	-	634,790.0	3,019,847	5.68	-
22. B.B.#4 (GAS)	155	1,360	1.2	-	-	-	GAS	16,070	1,028,002	16,520.0	78,589	5.78	4.89
23. B.B.#4 (COAL)	422	25,870	8.5	-	-	-	COAL	13,950	22,496,774	313,830.0	952,197	3.68	68.26
24. BIG BEND #4 TOTAL	422	27,230	8.9	17.9	48.5	12,132	-	-	-	330,350.0	1,030,786	3.79	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	44,660	1,027,989	45,910.0	218,407	-	4.89
26. B.B.C.T.#4 TOTAL	56	2,090	5.2	98.3	67.9	12,660	GAS	25,740	1,027,972	26,460.0	125,880	6.02	4.89
27. B.B.C.T.#5 TOTAL	330	78,720	33.1	87.2	33.8	9,201	GAS	704,580	1,028,002	724,310.0	3,445,706	4.38	4.89
28. B.B.C.T.#6 TOTAL	330	87,460	36.8	51.8	37.5	9,202	GAS	782,860	1,028,000	804,780.0	3,826,529	4.38	4.89
29. BIG BEND STATION TOTAL	1,823	270,320	20.6	63.5	40.0	10,397	-	-	-	2,810,470.0	13,047,721	4.83	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	83,360	60.2	-	89.9	8,776	GAS	711,640	1,028,020	731,580.0	3,480,232	4.17	4.89
32. POLK #1 TOTAL	220	83,360	52.6	0.0	89.9	8,776	-	-	-	731,580.0	3,480,232	4.17	-
33. POLK #2 ST DUCT FIRING	120	6,840	7.9	-	57.0	8,281	GAS	55,090	1,028,136	56,640.0	269,414	3.94	4.89
34. POLK #2 ST W/O DUCT FIRING	341	254,910	-	-	-	-	-	1,715,318	1,028,002	1,763,350.0	8,388,659	3.29	4.89
35. POLK #2 ST TOTAL	461	261,750	78.7	-	119.5	6,953	GAS	-	-	1,819,990.0	8,658,073	3.31	-
36. POLK #2 CT (GAS)	150	17,610	16.3	-	76.2	11,606	GAS	198,820	1,028,015	204,390.0	972,318	5.52	4.89
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	45,941	30.63	137.96
38. POLK #2 TOTAL	⁽⁴⁾ 150	17,760	16.4	-	76.4	11,618	-	-	-	206,340.0	1,018,259	5.73	-
39. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. POLK #3 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
41. POLK #3 TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	-	-	-	0.0	0	0.00	-
42. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	10,680	9.9	-	81.8	11,378	GAS	118,210	1,028,001	121,520.0	578,099	5.41	4.89
43. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	8,040	7.4	-	85.1	11,249	GAS	87,980	1,027,961	90,440.0	430,261	5.35	4.89
44. POLK #2 CC TOTAL	1,061	298,230	39.0	0.0	104.0	7,505	-	-	-	2,238,290.0	10,684,692	3.58	-
45. POLK STATION TOTAL	1,281	381,590	41.3	0.0	98.6	7,783	-	-	-	2,969,870.0	14,164,924	3.71	-
46. BAYSIDE #1	720	243,960	47.0	64.9	73.5	7,355	GAS	1,745,420	1,027,993	1,794,280.0	8,535,871	3.50	4.89
47. BAYSIDE #2	954	378,000	55.0	58.5	60.6	7,511	GAS	2,761,780	1,028,000	2,839,110.0	13,506,318	3.57	4.89
48. BAYSIDE #3	56	2,610	6.5	98.6	80.4	12,115	GAS	30,780	1,027,290	31,620.0	150,528	5.77	4.89
49. BAYSIDE #4	56	2,090	5.2	98.6	77.8	12,316	GAS	25,040	1,027,955	25,740.0	122,457	5.86	4.89
50. BAYSIDE #5	56	3,350	8.3	98.6	75.7	12,313	GAS	40,120	1,028,166	41,250.0	196,204	5.86	4.89
51. BAYSIDE #6	56	2,670	6.6	98.6	74.5	12,375	GAS	32,140	1,028,002	33,040.0	157,179	5.89	4.89
52. BAYSIDE STATION TOTAL	1,898	632,680	46.2	65.6	65.2	7,532	GAS	4,635,280	1,027,994	4,765,040.0	22,668,557	3.58	4.89

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MWH)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	160	1.1	-	1.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,700	241.9	-	241.9	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	8,500	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	8,500	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	10,420	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	7,070	15.6	-	15.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	6,480	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,050	18.1	-	18.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	5,620	15.3	-	15.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	10,490	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	10,460	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	7,470	16.8	-	16.8	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,020	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	6,350	11.5	-	11.5	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	9,010	23.2	-	23.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	9,010	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽²⁾ 877.7	110,870	17.0	-	17.0	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	355	19,280	7.3	-	-	-	GAS	220,730	1,027,998	226,910.0	1,119,759	5.81	5.07
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	355	19,280	7.3	83.9	53.8	11,769	-	-	-	226,910.0	1,119,759	5.81	-
24. B.B.#4 (GAS)	160	8,350	7.0	-	-	-	GAS	93,250	1,027,989	95,860.0	473,056	5.67	5.07
25. B.B.#4 (COAL)	432	158,610	43.3	-	-	-	COAL	80,950	22,500,062	1,821,380.0	5,503,061	3.47	67.98
26. BIG BEND #4 TOTAL	432	166,960	51.9	89.7	56.5	11,483	-	-	-	1,917,240.0	5,976,117	3.58	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	10,860	1,027,624	11,160.0	55,093	-	5.07
28. B.B.C.T.#4 TOTAL	61	380	0.8	98.3	56.6	13,184	GAS	4,880	1,026,639	5,010.0	24,756	6.51	5.07
29. B.B.C.T.#5 TOTAL	350	38,200	14.7	57.3	66.1	9,526	GAS	353,980	1,027,968	363,880.0	1,795,734	4.70	5.07
30. B.B.C.T.#6 TOTAL	350	13,880	5.3	97.1	52.2	9,656	GAS	130,380	1,027,995	134,030.0	661,415	4.77	5.07
31. BIG BEND STATION TOTAL	1,898	238,700	16.9	67.7	57.3	11,090	-	-	-	2,647,070.0	9,632,874	4.04	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	192	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #1 TOTAL	220	0	0.0	0.0	0.0	0	-	-	-	0.0	0	0.00	-
35. POLK #2 ST DUCT FIRING	120	8,580	9.6	-	68.1	8,175	GAS	68,230	1,027,994	70,140.0	346,130	4.03	5.07
36. POLK #2 ST W/O DUCT FIRING	360	614,500	-	-	-	-	-	4,141,185	1,028,003	4,257,150.0	21,008,159	3.42	5.07
37. POLK #2 ST TOTAL	480	623,080	174.5	-	155.1	6,945	GAS	-	-	4,327,290.0	21,354,289	3.43	-
38. POLK #2 CT (GAS)	180	1,380	1.0	-	76.7	11,000	GAS	14,770	1,027,759	15,180.0	74,927	5.43	5.07
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,757	30.50	137.41
40. POLK #2 TOTAL	⁽⁴⁾ 180	1,530	1.1	-	77.0	11,196	-	-	-	17,130.0	120,684	7.89	-
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,756	30.50	137.41
43. POLK #3 TOTAL	⁽⁴⁾ 180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,756	30.50	-
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 180	1,240	0.9	-	76.5	10,968	GAS	13,230	1,027,967	13,600.0	67,116	5.41	5.07
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,200	626,000	70.1	98.0	153.2	6,965	-	-	-	4,359,970.0	21,587,845	3.45	-
47. POLK STATION TOTAL	1,420	626,000	59.3	82.8	153.2	6,965	-	-	-	4,359,970.0	21,587,845	3.45	-
48. BAYSIDE #1	792	385,590	65.4	97.3	70.6	7,250	GAS	2,719,560	1,028,001	2,795,710.0	13,796,280	3.58	5.07
49. BAYSIDE #2	1,047	155,660	20.0	97.4	35.3	7,797	GAS	1,180,610	1,028,011	1,213,680.0	5,989,214	3.85	5.07
50. BAYSIDE #3	61	530	1.2	98.6	66.8	12,491	GAS	6,440	1,027,950	6,620.0	32,670	6.16	5.07
51. BAYSIDE #4	61	470	1.0	98.6	70.0	12,383	GAS	5,660	1,028,269	5,820.0	28,713	6.11	5.07
52. BAYSIDE #5	61	1,020	2.2	98.6	72.7	12,059	GAS	11,960	1,028,428	12,300.0	60,673	5.95	5.07
53. BAYSIDE #6	61	920	2.0	98.6	71.8	12,196	GAS	10,910	1,028,414	11,220.0	55,346	6.02	5.07
54. BAYSIDE STATION TOTAL	2,083	544,190	35.1	97.5	54.9	7,434	GAS	3,935,140	1,028,007	4,045,350.0	19,962,896	3.67	5.07
55. SYSTEM TOTAL	6,279	1,519,760	32.5	71.6	90.1	7,272	-	-	-	11,052,390.0	51,183,615	3.37	-

LEGEND:

⁽¹⁾ As burned fuel cost system total includes ignition

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E5

	ACTUAL					
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT (\$)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT (\$)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT (\$)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	0	0	0	5,311	0	0
16. UNIT COST (\$/BBL)	0.00	0.00	0.00	86.72	0.00	0.00
17. AMOUNT (\$)	0	0	0	460,555	0	0
18. BURNED:						
19. UNITS (BBL)	115	588	121	408	184	365
20. UNIT COST (\$/BBL)	148.10	148.38	148.17	140.61	140.45	140.70
21. AMOUNT (\$)	17,031	87,245	17,929	57,370	25,842	51,354
22. ENDING INVENTORY:						
23. UNITS (BBL)	38,114	37,526	37,406	42,309	42,125	41,760
24. UNIT COST (\$/BBL)	148.42	148.42	148.41	140.75	140.75	140.75
25. AMOUNT (\$)	5,656,781	5,569,536	5,551,607	5,954,792	5,928,950	5,877,596
26. DAYS SUPPLY: NORMAL	632	623	621	702	699	693
27. DAYS SUPPLY: EMERGENCY	5	5	5	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	36,182	20,086	91,883	51,062	96,156	29,578
30. UNIT COST (\$/TON)	68.37	49.48	76.55	72.96	50.60	63.90
31. AMOUNT (\$)	2,473,940	993,842	7,033,540	3,725,659	4,865,552	1,890,054
32. BURNED:						
33. UNITS (TONS)	36,182	90,829	58,946	32,825	49,854	86,003
34. UNIT COST (\$/TON)	69.75	82.55	81.43	85.41	77.25	70.52
35. AMOUNT (\$)	2,523,735	7,498,306	4,799,736	2,803,672	3,851,041	6,065,132
36. ENDING INVENTORY:						
37. UNITS (TONS)	243,210	172,467	205,404	223,641	269,943	213,518
38. UNIT COST (\$/TON)	73.88	72.05	73.38	73.28	65.89	65.58
39. AMOUNT (\$)	17,967,736	12,426,070	15,071,760	16,388,812	17,787,482	14,001,965
40. DAYS SUPPLY:	163	129	153	111	118	91
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	8,957,328	7,770,059	9,957,967	10,158,688	11,564,720	10,457,690
43. UNIT COST (\$/MCF)	2.12	3.81	5.18	3.44	4.04	4.44
44. AMOUNT (\$)	19,015,576	29,595,798	51,567,813	34,948,873	46,685,843	46,402,414
45. BURNED:						
46. UNITS (MCF)	9,027,318	8,122,935	9,620,165	10,225,351	11,410,833	10,516,609
47. UNIT COST (\$/MCF)	3.60	3.88	3.75	3.44	4.05	4.43
48. AMOUNT (\$)	32,506,200	31,540,062	36,066,578	35,178,663	46,203,567	46,581,068
49. ENDING INVENTORY:						
50. UNITS (MCF)	396,695	43,819	381,621	314,958	468,845	409,926
51. UNIT COST (\$/MCF)	2.64	2.89	2.98	2.88	2.97	3.13
52. AMOUNT (\$)	1,046,930	126,824	1,138,159	908,369	1,390,645	1,282,888
53. DAYS SUPPLY:	1	0	1	1	1	1
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT (\$)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT (\$)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT (\$)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT (\$)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING

(1) LIGHT OIL-IGNITION, OTHER USAGE, AND ANALYSIS

(2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENTS

(3) GAS-IGNITION AND ADDITIVES

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

SCHEDULE E5

	Jul-21	Aug-21	Estimated Sep-21	Oct-21	Nov-21	Dec-21	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	0	0	0	0	0	0	0
3. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT (\$)	0	0	0	0	0	0	0
5. BURNED:							
6. UNITS (BBL)	0	0	0	0	0	0	0
7. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT (\$)	0	0	0	0	0	0	0
9. ENDING INVENTORY:							
10. UNITS (BBL)	0	0	0	0	0	0	0
11. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT (\$)	0	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	665	665	665	665	333	665	8,969
16. UNIT COST (\$/BBL)	102.19	102.80	102.91	102.93	102.72	102.78	93.25
17. AMOUNT (\$)	67,954	68,362	68,438	68,450	34,207	68,349	836,315
18. BURNED:							
19. UNITS (BBL)	666	666	666	666	333	666	5,444
20. UNIT COST (\$/BBL)	139.97	139.38	138.81	138.24	137.96	137.41	140.48
21. AMOUNT (\$)	93,217	92,828	92,445	92,069	45,941	91,513	764,784
22. ENDING INVENTORY:							
23. UNITS (BBL)	41,760	41,760	41,760	41,760	41,760	41,760	41,760
24. UNIT COST (\$/BBL)	140.14	139.56	138.98	138.42	138.13	137.58	137.58
25. AMOUNT (\$)	5,852,333	5,827,867	5,803,859	5,780,241	5,768,507	5,745,343	5,745,343
26. DAYS SUPPLY: NORMAL	1,993	1,993	1,993	1,993	1,993	1,910	-
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
COAL							
28. PURCHASES:							
29. UNITS (TONS)	95,000	70,000	55,000	52,500	52,500	40,000	689,947
30. UNIT COST (\$/TON)	60.90	57.80	57.80	60.67	60.67	57.80	61.85
31. AMOUNT (\$)	5,785,728	4,046,151	3,179,119	3,184,964	3,184,964	2,312,087	42,675,600
32. BURNED:							
33. UNITS (TONS)	74,450	80,160	72,930	15,640	13,950	80,950	692,719
34. UNIT COST (\$/TON)	70.50	69.04	68.19	70.91	68.26	67.98	73.42
35. AMOUNT (\$)	5,248,735	5,533,990	4,972,764	1,109,083	952,197	5,503,061	50,861,452
36. ENDING INVENTORY:							
37. UNITS (TONS)	234,068	223,908	205,978	242,838	281,388	240,438	240,438
38. UNIT COST (\$/TON)	64.07	62.53	61.44	61.23	61.08	60.28	60.28
39. AMOUNT (\$)	14,996,551	14,001,400	12,656,006	14,868,015	17,186,523	14,493,093	14,493,093
40. DAYS SUPPLY:	95	122	183	202	155	100	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	10,933,834	11,289,625	10,723,105	10,542,335	9,995,638	8,986,635	121,337,624
43. UNIT COST (\$/MCF)	4.99	5.03	5.00	4.95	4.89	5.08	4.45
44. AMOUNT (\$)	54,611,635	56,734,454	53,604,987	52,187,993	48,899,784	45,624,400	539,879,570
45. BURNED:							
46. UNITS (MCF)	10,954,655	11,289,625	10,723,105	10,542,335	9,995,638	8,986,635	121,415,204
47. UNIT COST (\$/MCF)	4.97	5.02	5.00	4.95	4.89	5.07	4.44
48. AMOUNT (\$)	54,447,723	56,722,534	53,615,547	52,189,513	48,883,064	45,589,041	539,523,560
49. ENDING INVENTORY:							
50. UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105	389,105
51. UNIT COST (\$/MCF)	3.72	3.75	3.72	3.72	3.76	3.85	3.85
52. AMOUNT (\$)	1,446,800	1,458,720	1,448,161	1,446,640	1,463,360	1,498,720	1,498,720
53. DAYS SUPPLY:	1	1	1	1	1	1	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT (\$)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT (\$)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT (\$)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT (\$)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING

(1) LIGHT OIL-IGNITION AND ANALYSIS (2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENTS (3) GAS-IGNITION

TAMPA ELECTRIC COMPANY
POWER SOLD
ACTUAL FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH		CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES	
				WHEELED	FROM OWN	(A)	(B)				
				OTHER SYSTEMS	GENERATION	FUEL COST	TOTAL COST				
ACTUAL											
Jan-21	SEMINOLE	JURISD.	SCH. - D	3,130.0	0.0	3,130.0	1.925	2.118	60,254.47	66,279.92	4,066.61
	VARIOUS	JURISD.	SCH. - MA	500.0	0.0	500.0	6.817	3.562	34,082.75	17,808.52	(19,569.73)
	TOTAL			3,630.0	0.0	3,630.0	2.599	2.316	94,337.22	84,088.44	(15,503.12)
ACTUAL											
Feb-21	SEMINOLE	JURISD.	SCH. - D	3,307.0	0.0	3,307.0	3.635	3.998	120,198.44	132,218.28	9,721.57
	VARIOUS	JURISD.	SCH. - MA	1,413.0	0.0	1,413.0	3.639	5.260	51,415.96	74,324.82	22,413.29
	TOTAL			4,720.0	0.0	4,720.0	3.636	4.376	171,614.40	206,543.10	32,134.86
ACTUAL											
Mar-21	SEMINOLE	JURISD.	SCH. - D	3,060.0	0.0	3,060.0	1.867	2.054	57,128.87	62,841.76	3,704.76
	VARIOUS	JURISD.	SCH. - MA	40.0	0.0	40.0	1.707	2.694	682.80	1,077.51	320.31
	TOTAL			3,100.0	0.0	3,100.0	1.865	2.062	57,811.67	63,919.27	4,025.07
ACTUAL											
Apr-21	SEMINOLE	JURISD.	SCH. - D	2,431.0	0.0	2,431.0	1.776	1.953	43,172.02	47,489.22	3,339.30
	VARIOUS	JURISD.	SCH. - MA	2,625.0	0.0	2,625.0	2.063	3.223	54,157.50	84,605.56	25,667.06
	TOTAL			5,056.0	0.0	5,056.0	1.925	2.613	97,329.52	132,094.78	29,006.36
ACTUAL											
May-21	SEMINOLE	JURISD.	SCH. - D	1,623.0	0.0	1,623.0	1.903	2.094	30,891.60	33,980.76	2,293.51
	VARIOUS	JURISD.	SCH. - MA	5,300.0	0.0	5,300.0	2.244	3.343	118,945.00	177,162.07	47,628.07
	TOTAL			6,923.0	0.0	6,923.0	2.164	3.050	149,836.60	211,142.83	49,921.58
ACTUAL											
Jun-21	SEMINOLE	JURISD.	SCH. - D	1,621.0	0.0	1,621.0	1.998	2.198	32,389.91	35,628.90	1,782.60
	VARIOUS	JURISD.	SCH. - MA	2,090.0	0.0	2,090.0	2.315	3.754	48,384.15	78,457.89	26,082.94
	TOTAL			3,711.0	0.0	3,711.0	2.177	3.074	80,774.06	114,086.79	27,865.54

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH		CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES	
				WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST				
ESTIMATED											
Jul-21	SEMINOLE	JURISD.	SCH. - D	2,880.0	0.0	2,880.0	2.937	3.144	84,590.00	5,962.00	
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			2,880.0	0.0	2,880.0	2.937	3.144	84,590.00	90,552.00	5,962.00
ESTIMATED											
Aug-21	SEMINOLE	JURISD.	SCH. - D	2,980.0	0.0	2,980.0	2.930	3.136	87,310.00	93,463.00	6,153.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,980.0	0.0	2,980.0	2.930	3.136	87,310.00	93,463.00	6,153.00
ESTIMATED											
Sep-21	SEMINOLE	JURISD.	SCH. - D	2,970.0	0.0	2,970.0	2.862	3.064	85,010.00	91,001.00	5,991.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,970.0	0.0	2,970.0	2.862	3.064	85,010.00	91,001.00	5,991.00
ESTIMATED											
Oct-21	SEMINOLE	JURISD.	SCH. - D	2,880.0	0.0	2,880.0	2.802	2.999	80,690.00	86,377.00	5,687.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,880.0	0.0	2,880.0	2.802	2.999	80,690.00	86,377.00	5,687.00
ESTIMATED											
Nov-21	SEMINOLE	JURISD.	SCH. - D	2,920.0	0.0	2,920.0	3.113	3.332	90,900.00	97,306.00	6,406.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,920.0	0.0	2,920.0	3.113	3.332	90,900.00	97,306.00	6,406.00
ESTIMATED											
Dec-21	SEMINOLE	JURISD.	SCH. - D	2,940.0	0.0	2,940.0	3.047	3.262	89,580.00	95,893.00	6,313.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,940.0	0.0	2,940.0	3.047	3.262	89,580.00	95,893.00	6,313.00
TOTAL											
Jan-21	SEMINOLE	JURISD.	SCH. - D	32,742.0	0.0	32,742.0	2.633	2.850	862,115.31	933,030.84	61,420.35
THRU	VARIOUS	JURISD.	SCH. - MA	11,968.0	0.0	11,968.0	2.571	3.622	307,668.16	433,436.37	102,541.94
Dec-21	TOTAL			44,710.0	0.0	44,710.0	2.616	3.056	1,169,783.47	1,366,467.21	163,962.29

TAMPA ELECTRIC COMPANY PURCHASED POWER (EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES) ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021							SCHEDULE E7		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL \$ FOR FUEL ADJUSTMENT
ACTUAL									
Jan-21	VARIOUS	SCH. - J	152,282.0	0.0	0.0	152,282.0	3.346	3.346	5,095,948.34
	VARIOUS	OATT	1,350.0	0.0	0.0	1,350.0	2.794	2.794	37,714.91
	TOTAL		153,632.0	0.0	0.0	153,632.0	3.342	3.342	5,133,663.25
ACTUAL									
Feb-21	VARIOUS	SCH. - J	14,230.0	0.0	0.0	14,230.0	8.326	8.326	1,184,807.77
	VARIOUS	OATT	183.0	0.0	0.0	183.0	6.823	6.823	12,485.55
	TOTAL		14,413.0	0.0	0.0	14,413.0	8.307	8.307	1,197,293.32
ACTUAL									
Mar-21	VARIOUS	SCH. - J	10,482.0	0.0	0.0	10,482.0	6.764	6.764	708,966.14
	VARIOUS	OATT	105.0	0.0	0.0	105.0	7.336	7.336	7,702.64
	TOTAL		10,587.0	0.0	0.0	10,587.0	6.769	6.769	716,668.78
ACTUAL									
Apr-21	VARIOUS	SCH. - J	5,012.0	0.0	0.0	5,012.0	5.302	5.302	265,748.50
	VARIOUS	OATT	1,065.0	0.0	0.0	1,065.0	3.852	3.852	41,020.42
	TOTAL		6,077.0	0.0	0.0	6,077.0	5.048	5.048	306,768.92
ACTUAL									
May-21	VARIOUS	SCH. - J	16,005.0	0.0	0.0	16,005.0	8.360	8.360	1,338,078.77
	VARIOUS	OATT	1,266.0	0.0	0.0	1,266.0	4.018	4.018	50,872.12
	TOTAL		17,271.0	0.0	0.0	17,271.0	8.042	8.042	1,388,950.89
ACTUAL									
Jun-21	VARIOUS	SCH. - J	20,160.0	0.0	0.0	20,160.0	4.052	4.052	816,922.17
	VARIOUS	OATT	1,196.0	0.0	0.0	1,196.0	3.778	3.778	45,183.47
	TOTAL		21,356.0	0.0	0.0	21,356.0	4.037	4.037	862,105.64
ESTIMATED									
Jul-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Aug-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Sep-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Oct-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Nov-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Dec-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL									
Jan-21	VARIOUS	SCH. - J	218,171.0	0.0	0.0	218,171.0	4.313	4.313	9,410,471.69
THRU	VARIOUS	OATT	5,165.0	0.0	0.0	5,165.0	3.775	3.775	194,979.11
Dec-21	TOTAL		223,336.0	0.0	0.0	223,336.0	4.301	4.301	9,605,450.80

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL \$ FOR FUEL ADJUSTMENT
ACTUAL Jan-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	4.0 3,505.0	0.0 0.0	0.0 0.0	4.0 3,505.0	2.208 1.861	2.208 1.861	88.26 65,231.34
	TOTAL		3,509.0	0.0	0.0	3,509.0	1.861	1.861	65,319.60
ACTUAL Feb-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	2,415.0 8,488.0	0.0 0.0	0.0 0.0	2,415.0 8,488.0	1.813 3.573	1.813 3.573	43,774.05 303,300.02
	TOTAL		10,903.0	0.0	0.0	10,903.0	3.183	3.183	347,074.07
ACTUAL Mar-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	131.2 10,325.0	0.0 0.0	0.0 0.0	131.2 10,325.0	1.811 2.052	1.811 2.052	2,375.51 211,878.38
	TOTAL		10,456.2	0.0	0.0	10,456.2	2.049	2.049	214,253.89
ACTUAL Apr-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	24.1 2,978.0	0.0 0.0	0.0 0.0	24.1 2,978.0	1.814 1.696	1.814 1.696	437.85 50,503.23
	TOTAL		3,002.1	0.0	0.0	3,002.1	1.697	1.697	50,941.08
ACTUAL May-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	16.9 9,085.0	0.0 0.0	0.0 0.0	16.9 9,085.0	1.814 1.999	1.814 1.999	306.62 181,581.07
	TOTAL		9,101.9	0.0	0.0	9,101.9	1.998	1.998	181,887.69
ACTUAL Jun-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	33.5 10,697.0	0.0 0.0	0.0 0.0	33.5 10,697.0	1.814 2.140	1.814 2.140	606.82 228,944.75
	TOTAL		10,730.5	0.0	0.0	10,730.5	2.139	2.139	229,551.57
ESTIMATED Jul-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,060.0	0.0 0.0	0.0 0.0	0.0 5,060.0	0.000 3.622	0.000 3.622	0.00 183,290.00
	TOTAL		5,060.0	0.0	0.0	5,060.0	3.622	3.622	183,290.00
ESTIMATED Aug-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,230.0	0.0 0.0	0.0 0.0	0.0 5,230.0	0.000 3.604	0.000 3.604	0.00 188,490.00
	TOTAL		5,230.0	0.0	0.0	5,230.0	3.604	3.604	188,490.00
ESTIMATED Sep-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,160.0	0.0 0.0	0.0 0.0	0.0 5,160.0	0.000 3.132	0.000 3.132	0.00 161,600.00
	TOTAL		5,160.0	0.0	0.0	5,160.0	3.132	3.132	161,600.00
ESTIMATED Oct-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,120.0	0.0 0.0	0.0 0.0	0.0 5,120.0	0.000 2.980	0.000 2.980	0.00 152,560.00
	TOTAL		5,120.0	0.0	0.0	5,120.0	2.980	2.980	152,560.00
ESTIMATED Nov-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,160.0	0.0 0.0	0.0 0.0	0.0 5,160.0	0.000 2.909	0.000 2.909	0.00 150,110.00
	TOTAL		5,160.0	0.0	0.0	5,160.0	2.909	2.909	150,110.00
ESTIMATED Dec-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,160.0	0.0 0.0	0.0 0.0	0.0 5,160.0	0.000 2.612	0.000 2.612	0.00 134,790.00
	TOTAL		5,160.0	0.0	0.0	5,160.0	2.612	2.612	134,790.00
TOTAL Jan-21 THRU Dec-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	2,624.7 75,968.0	0.0 0.0	0.0 0.0	2,624.7 75,968.0	1.813 2.649	1.813 2.649	47,589.11 2,012,278.79
	TOTAL		78,592.7	0.0	0.0	78,592.7	2.621	2.621	2,059,867.90

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	TRANSACTION COST cents/KWH	TOTAL \$ FOR FUEL ADJUSTMENT	COST IF GENERATED		FUEL SAVINGS (9B)-(8)
								(A) CENTS PER KWH	(B) DOLLARS	
ACTUAL	VARIOUS	SCH. - J	4,234.0	0.0	4,234.0	12.944	548,031.26	13.326	564,225.22	16,193.96
Jan-21	TOTAL		4,234.0	0.0	4,234.0	12.944	548,031.26	13.326	564,225.22	16,193.96
ACTUAL	VARIOUS	SCH. - J	64,475.0	0.0	64,475.0	3.696	2,383,160.78	3.759	2,423,920.49	40,759.71
Feb-21	TOTAL		64,475.0	0.0	64,475.0	3.696	2,383,160.78	3.759	2,423,920.49	40,759.71
ACTUAL	VARIOUS	SCH. - J	78,270.0	0.0	78,270.0	4.443	3,477,145.25	5.006	3,918,277.25	441,132.00
Mar-21	TOTAL		78,270.0	0.0	78,270.0	4.443	3,477,145.25	5.006	3,918,277.25	441,132.00
ACTUAL	VARIOUS	SCH. - J	117,300.0	0.0	117,300.0	2.959	3,470,960.00	3.312	3,884,958.00	413,998.00
Apr-21	TOTAL		117,300.0	0.0	117,300.0	2.959	3,470,960.00	3.312	3,884,958.00	413,998.00
ACTUAL	VARIOUS	SCH. - J	258,930.0	0.0	258,930.0	3.586	9,286,373.47	3.957	10,245,597.41	959,223.94
May-21	TOTAL		258,930.0	0.0	258,930.0	3.586	9,286,373.47	3.957	10,245,597.41	959,223.94
ACTUAL	VARIOUS	SCH. - J	273,570.0	0.0	273,570.0	3.359	9,189,425.75	3.716	10,165,453.55	976,027.80
Jun-21	TOTAL		273,570.0	0.0	273,570.0	3.359	9,189,425.75	3.716	10,165,453.55	976,027.80
ESTIMATED	VARIOUS	SCH. - J	271,550.0	0.0	271,550.0	4.228	11,480,270.00	5.332	14,480,050.00	2,999,780.00
Jul-21	TOTAL		271,550.0	0.0	271,550.0	4.228	11,480,270.00	5.332	14,480,050.00	2,999,780.00
ESTIMATED	VARIOUS	SCH. - J	271,700.0	0.0	271,700.0	4.227	11,484,420.00	5.322	14,458,780.00	2,974,360.00
Aug-21	TOTAL		271,700.0	0.0	271,700.0	4.227	11,484,420.00	5.322	14,458,780.00	2,974,360.00
ESTIMATED	VARIOUS	SCH. - J	262,540.0	0.0	262,540.0	4.039	10,604,920.00	5.181	13,600,890.00	2,995,970.00
Sep-21	TOTAL		262,540.0	0.0	262,540.0	4.039	10,604,920.00	5.181	13,600,890.00	2,995,970.00
ESTIMATED	VARIOUS	SCH. - J	267,060.0	0.0	267,060.0	4.130	11,029,890.00	5.316	14,196,940.00	3,167,050.00
Oct-21	TOTAL		267,060.0	0.0	267,060.0	4.130	11,029,890.00	5.316	14,196,940.00	3,167,050.00
ESTIMATED	VARIOUS	SCH. - J	72,880.0	0.0	72,880.0	3.575	2,605,660.00	5.113	3,726,530.00	1,120,870.00
Nov-21	TOTAL		72,880.0	0.0	72,880.0	3.575	2,605,660.00	5.113	3,726,530.00	1,120,870.00
ESTIMATED	VARIOUS	SCH. - J	2,040.0	0.0	2,040.0	5.515	112,500.00	31.914	651,050.00	538,550.00
Dec-21	TOTAL		2,040.0	0.0	2,040.0	5.515	112,500.00	31.914	651,050.00	538,550.00
TOTAL										
Jan-21										
THRU	VARIOUS	SCH. - J	1,944,549.0	0.0	1,944,549.0	3.892	75,672,756.51	4.747	92,316,671.92	16,643,915.41
Dec-21	TOTAL		1,944,549.0	0.0	1,944,549.0	3.892	75,672,756.51	4.747	92,316,671.92	16,643,915.41

**EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE**

DOCUMENT NO. 2

CAPACITY COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2021 THROUGH DECEMBER 2021

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2021 THROUGH DECEMBER 2021

1.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2021 THROUGH DECEMBER 2021	(5,764,325)
2.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2020 THROUGH DECEMBER 2020 INCLUDED IN 2021	(1,583,299)
3.	PROJECTED OVER/(UNDER) RECOVERY TRUE-UP INCLUDED IN JUNE - DECEMBER 2021 FACTORS (Per Mid-Course Petition, Exhibit D, Page 5 of 6, Line 8a)	8,503,428
4.	PROJECTED OVER/(UNDER) RECOVERY TRUE-UP INCLUDED IN JANUARY - AUGUST 2021 FACTORS (Per Mid-Course Petition, Exhibit D, Page 5 of 6, Line 8)	<u>(1,180,984)</u>
5.	MID-COURSE TRUE-UP OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2021 THROUGH DECEMBER 2021 (SUM OF LINES 2 - 4)	5,739,145
6.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2022 THROUGH DECEMBER 2022 (LINE 1 + LINE 5)	<u><u>(25,180)</u></u>

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
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 UNIT POWER CAPACITY CHARGES	2,069,886	1,125,101	385,048	704,682	(152,499)	1,179,112	1,176,770	1,176,770	706,062	706,062	353,031	0	9,430,025
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3 (UNIT POWER CAPACITY REVENUES)	(16,605)	(45,584)	(79,683)	(82,822)	(68,010)	(57,180)	(69,183)	(69,183)	(69,183)	(69,183)	(69,183)	(307,601)	(1,003,400)
4 TOTAL CAPACITY DOLLARS	2,053,281	1,079,517	305,365	621,860	(220,509)	1,121,932	1,107,587	1,107,587	636,879	636,879	283,848	(307,601)	8,426,625
5 SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6 JURISDICTIONAL CAPACITY DOLLARS	2,053,281	1,079,517	305,365	621,860	(220,509)	1,121,932	1,107,587	1,107,587	636,879	636,879	283,848	(307,601)	8,426,625
7 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	28,366	28,712	28,523	30,704	33,405	36,878	37,942	37,791	2,852,549	2,621,989	2,180,368	2,078,873	9,996,100
8 PRIOR PERIOD TRUE-UP PROVISION	147,623	147,623	147,623	147,623	147,623	147,623	147,623	147,623	0	0	0	0	1,180,984
8a MID-COURSE TRUE-UP PROVISION	0	0	0	0	0	0	0	0	(2,125,857)	(2,125,857)	(2,125,857)	(2,125,857)	(8,503,428)
9 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	175,989	176,335	176,146	178,327	181,028	184,501	185,565	185,414	726,692	496,132	54,511	(46,984)	2,673,656
10 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 9 - Line 6)	(1,877,292)	(903,182)	(129,219)	(443,533)	401,537	(937,431)	(922,022)	(922,173)	89,813	(140,747)	(229,337)	260,617	(5,752,969)
11 INTEREST PROVISION FOR MONTH	(234)	(372)	(384)	(419)	(270)	(291)	(1,310)	(2,549)	(2,367)	(1,695)	(1,075)	(390)	(11,356)
12 ADJUSTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
13 TRUE-UP AND INT. PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(1,583,299)	(3,608,448)	(4,659,625)	(4,936,851)	(5,528,426)	(5,274,782)	(6,360,127)	(7,431,082)	(8,503,427)	(6,290,124)	(4,306,709)	(2,411,264)	(1,583,299)
14 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	2,125,857	2,125,857	2,125,857	2,125,857	7,322,444
15 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 10 - 14)	(3,608,448)	(4,659,625)	(4,936,851)	(5,528,426)	(5,274,782)	(6,360,127)	(7,431,082)	(8,503,427)	(6,290,124)	(4,306,709)	(2,411,264)	(25,180)	(25,180)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
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 BEGINNING TRUE-UP AMOUNT	(1,583,299)	(3,608,448)	(4,659,625)	(4,936,851)	(5,528,426)	(5,274,782)	(6,360,127)	(7,431,082)	(8,503,427)	(6,290,124)	(4,306,709)	(2,411,264)	(1,583,299)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(3,608,214)	(4,659,253)	(4,936,467)	(5,528,007)	(5,274,512)	(6,359,836)	(7,429,772)	(8,500,878)	(6,287,757)	(4,305,014)	(2,410,189)	(24,790)	(13,824)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT (LINE 1 + LINE 2)	(5,191,514)	(8,267,702)	(9,596,093)	(10,464,859)	(10,802,939)	(11,634,619)	(13,789,900)	(15,931,961)	(14,791,185)	(10,595,139)	(6,716,899)	(2,436,055)	(1,597,124)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(2,595,757)	(4,133,851)	(4,798,046)	(5,232,429)	(5,401,469)	(5,817,309)	(6,894,950)	(7,965,980)	(7,395,592)	(5,297,569)	(3,358,449)	(1,218,027)	(798,562)
5 INTEREST RATE % - 1ST DAY OF MONTH-	0.100	0.120	0.090	0.110	0.070	0.040	0.080	0.380	0.380	0.380	0.380	0.380	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH-	0.120	0.090	0.110	0.070	0.040	0.080	0.380	0.380	0.380	0.380	0.380	0.380	NA
7 TOTAL (LINE 5 + LINE 6)	0.220	0.210	0.200	0.180	0.110	0.120	0.460	0.760	0.760	0.760	0.760	0.760	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	0.110	0.105	0.100	0.090	0.055	0.060	0.230	0.380	0.380	0.380	0.380	0.380	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.009	0.009	0.008	0.008	0.005	0.005	0.019	0.032	0.032	0.032	0.032	0.032	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(234)	(372)	(384)	(419)	(270)	(291)	(1,310)	(2,549)	(2,367)	(1,695)	(1,075)	(390)	(11,356)

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E12

CONTRACT	TERM		CONTRACT TYPE	
	START	END		
SEMINOLE ELECTRIC **	6/1/1992	-----	LT	QF = QUALIFYING FACILITY LT = LONG TERM ST = SHORT-TERM ** THREE YEAR NOTICE REQUIRED FOR TERMINATION.
FLORIDA MUNICIPAL POWER AGENCY	12/1/2020	2/28/2021	ST	
ORLANDO UTILITIES COMMISSION	12/1/2020	2/28/2021	ST	
FLORIDA POWER & LIGHT	12/1/2020	2/28/2021	ST	
ORLANDO UTILITIES COMMISSION	1/1/2021	1/31/2021	ST	

CONTRACT	ACT JANUARY MW	ACT FEBRUARY MW	ACT MARCH MW	ACT APRIL MW	ACT MAY MW	ACT JUNE MW	EST JULY MW	EST AUGUST MW	EST SEPTEMBER MW	EST OCTOBER MW	EST NOVEMBER MW	EST DECEMBER MW
SEMINOLE ELECTRIC	1.9	7.0	10.5	9.1	5.9	6.6	10.0	10.0	10.0	10.0	10.0	10.0
FLORIDA MUNICIPAL POWER AGENCY	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ORLANDO UTILITIES COMMISSION	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FLORIDA POWER & LIGHT	160.0	160.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ORLANDO UTILITIES COMMISSION	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

CAPACITY	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
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ORLANDO UTILITIES COMMISSION													
FLORIDA POWER & LIGHT													
DUKE ENERGY FLORIDA													
FLORIDA MUNICIPAL POWER AGENCY													
JACKSONVILLE ELECTRIC AUTHORITY													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
DUKE ENERGY FLORIDA - MA													
FLORIDA POWER & LIGHT - MA													
ORLANDO UTILITIES COMMISSION - MA													
EXGEN - MA													
THE ENERGY AUTHORITY - MA													
EDF TRADING - MA													
RAINBOW ENERGY - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	2,053,281	1,079,517	305,365	621,860	(220,508)	1,121,932	1,107,587	1,107,587	636,879	636,879	283,848	(307,601)	8,426,626
TOTAL CAPACITY	2,053,281	1,079,517	305,365	621,860	(220,508)	1,121,932	1,107,587	1,107,587	636,879	636,879	283,848	(307,601)	8,426,626

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 3

FUEL AND PURCHASED POWER COST RECOVERY NO MIDCOURSE

ACTUAL / ESTIMATED JANUARY 2021 THROUGH DECEMBER 2021

TAMPA ELECTRIC COMPANY

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**TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021**

SCHEDULE E1-A

1. ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2021 - December 2021 (6 months actual, 6 months estimated)	(\$77,449,533)
2. FINAL TRUE-UP (January 2020 - December 2020) (Per True-Up filed April 2, 2021)	<u>3,769,256</u>
3. TOTAL OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2022 (Line 1 + Line 2) To be included in the 12-month projected period January 2022 through December 2022	<u><u>(\$73,680,277)</u></u>
4. JURISDICTIONAL MWH SALES (Projected January 2022 through December 2022)	19,807,340
5. TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,776,928)	0.3726

TAMPA ELECTRIC COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E1-B

	ACTUAL						ESTIMATED						TOTAL
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	
A. 1. Fuel Cost of System Net Generation	35,046,966	39,125,613	40,884,243	38,039,705	50,080,450	52,697,554	59,789,675	62,349,352	58,680,756	53,390,665	49,881,202	51,183,615	591,149,796
2. Fuel Cost of Power Sold ⁽¹⁾	78,834	203,749	61,837	126,336	199,759	108,640	90,552	93,463	91,001	86,377	97,306	95,893	1,333,746
3. Fuel Cost of Purchased Power	5,133,663	1,197,293	716,669	306,769	1,388,951	862,106	0	0	0	0	0	0	9,605,451
3a. Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
3b. Payments to Qualifying Facilities	65,320	347,074	214,254	50,941	181,888	229,552	183,290	188,490	161,600	152,560	150,110	134,790	2,059,869
4. Energy Cost of Economy Purchases	548,031	2,383,161	3,477,145	3,470,960	9,286,373	9,189,426	11,480,270	11,484,420	10,604,920	11,029,890	2,605,660	112,500	75,672,756
5. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
5a. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
5b. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
6. TOTAL FUEL & NET POWER TRANS.	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,126
⁽¹⁾ Includes Gains													
B. 1. Jurisdictional MWH Sales	1,538,264	1,376,720	1,370,486	1,489,907	1,639,034	1,886,168	1,934,606	1,924,409	2,007,766	1,819,261	1,522,255	1,435,265	19,944,141
2. Non-Jurisdictional MWH Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
3. TOTAL SALES (LINE B1+B2)	1,538,264	1,376,720	1,370,486	1,489,907	1,639,034	1,886,168	1,934,606	1,924,409	2,007,766	1,819,261	1,522,255	1,435,265	19,944,141
4. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	-
C. 1. Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	48,037,811	42,754,413	42,417,459	46,397,644	51,575,423	60,000,677	62,056,327	61,610,667	64,519,834	57,776,416	47,586,655	44,594,527	629,327,853
1a. Jurisdictional Fuel Recovery Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
2. True-up Provision	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,255)	(2,123,250)	(25,479,055)
2a. Incentive Provision	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,171)	(238,175)	(2,858,056)
2b. 2019 Optimization Mechanism Gains	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,402)	(98,398)	(1,180,820)
3. FUEL REVENUE APPLICABLE TO PERIOD	45,577,983	40,294,585	39,957,631	43,937,816	49,115,595	57,540,849	59,596,499	59,150,839	62,060,006	55,316,588	45,126,827	42,134,704	599,809,922
4. Total Fuel and Net Power Transactions (Line A6)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,126
5. Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
5a. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	-
5b. Jurisdictional Sales Adjusted for Line Losses	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
5c. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
6. JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
7. Over/(Under) Recovery	4,862,837	(2,554,807)	(5,272,843)	2,195,777	(11,622,308)	(5,329,149)	(11,766,184)	(14,777,960)	(7,296,269)	(9,170,150)	(7,412,839)	(9,200,308)	(77,344,203)
8. Interest Provision	(1,640)	(1,345)	(1,339)	(1,292)	(937)	(1,255)	(5,989)	(13,656)	(16,513)	(18,473)	(20,453)	(22,438)	(105,330)
9. TOTAL ESTIMATED TRUE-UP FOR THE PERIOD													<u>(77,449,533)</u>

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	TOTAL
	Actual			Estimated			Estimated			Estimated			PERIOD
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	
1. Fuel Cost of System Net Generation	35,046,966	39,125,613	40,884,243	38,039,705	50,080,450	52,697,554	59,789,675	62,349,352	58,680,756	53,390,665	49,881,202	51,183,615	591,149,796
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold ⁽¹⁾	78,834	203,749	61,837	126,336	199,759	108,640	90,552	93,463	91,001	86,377	97,306	95,893	1,333,746
4. Fuel Cost of Purchased Power	5,133,663	1,197,293	716,669	306,769	1,388,951	862,106	0	0	0	0	0	0	9,605,451
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	65,320	347,074	214,254	50,941	181,888	229,552	183,290	188,490	161,600	152,560	150,110	134,790	2,059,869
7. Energy Cost of Economy Purchases	548,031	2,383,161	3,477,145	3,470,960	9,286,373	9,189,426	11,480,270	11,484,420	10,604,920	11,029,890	2,605,660	112,500	75,672,757
8. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
9. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
11. TOTAL FUEL & NET POWER TRANSACTIONS	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,127
12. Jurisdictional MWh Sold	1,538,264	1,376,720	1,370,486	1,489,907	1,639,034	1,886,168	1,934,606	1,924,409	2,007,766	1,819,261	1,522,255	1,435,265	19,944,141
13. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	-
14. Jurisdictional Total Fuel & Net Power Transactions (Line 11 * Line 13)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
15. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	-
16. Jurisdictional Sales Adjusted for Line Losses (Line 14 * Line 15)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
17. Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
18. JURISD. TOTAL FUEL & NET PWR. TRANS. (LINE 16+17)	40,715,146	42,849,392	45,230,474	41,742,039	60,737,903	62,869,998	71,362,683	73,928,799	69,356,275	64,486,738	52,539,666	51,335,012	677,154,125
19. Cost Per kWh Sold (Cents/kWh)	2.6468	3.1124	3.3003	2.8017	3.7057	3.3332	3.6887	3.8416	3.4544	3.5447	3.4514	3.5767	3.3953
20. Optimization Mechanism (Cents/kWh) ⁽²⁾	(0.0064)	(0.0071)	(0.0072)	(0.0066)	(0.0060)	(0.0052)	(0.0051)	(0.0051)	(0.0049)	(0.0054)	(0.0065)	(0.0069)	(0.0060)
21. True-up (Cents/kWh) ⁽²⁾	0.1380	0.1542	0.1549	0.1425	0.1295	0.1126	0.1098	0.1103	0.1058	0.1167	0.1395	0.1479	0.1301
22. Total (Cents/kWh) (Line 19+20+21)	2.7784	3.2595	3.4480	2.9376	3.8292	3.4406	3.7934	3.9468	3.5553	3.6560	3.5844	3.7177	3.5194
23. Revenue Tax Factor	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
24. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	2.7804	3.2619	3.4505	2.9397	3.8320	3.4431	3.7962	3.9497	3.5579	3.6586	3.5870	3.7204	3.5219
25. GPIF Adjusted for Taxes (Cents/kWh) ⁽²⁾	0.0155	0.0173	0.0174	0.0160	0.0145	0.0126	0.0123	0.0124	0.0119	0.0131	0.0156	0.0166	0.0146
26. TOTAL RECOVERY FACTOR (LINE 24+25)	2.7959	3.2792	3.4679	2.9557	3.8465	3.4557	3.8085	3.9621	3.5698	3.6717	3.6026	3.7370	3.5365
27. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	2.796	3.279	3.468	2.956	3.846	3.456	3.808	3.962	3.570	3.672	3.603	3.737	3.536

⁽¹⁾ Includes Gains

⁽²⁾ Based on Jurisdictional Sales Only

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E3

	ACTUAL					
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
FUEL COST OF SYSTEM NET GENERATION (\$)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	17,031	87,245	17,929	57,370	25,842	51,354
3. COAL	2,523,735	7,498,306	4,799,736	2,803,672	3,851,041	6,065,132
4. NATURAL GAS	32,506,200	31,540,062	36,066,578	35,178,663	46,203,567	46,581,068
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL (\$)	35,046,966	39,125,613	40,884,243	38,039,705	50,080,450	52,697,554
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	178	101	115	96	51	85
10. COAL	83,163	196,789	126,454	63,348	108,168	178,944
11. NATURAL GAS	1,151,915	1,023,714	1,230,975	1,277,518	1,393,547	1,403,874
12. SOLAR	82,335	86,652	117,281	133,120	150,867	110,572
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	1,317,591	1,307,256	1,474,825	1,474,082	1,652,633	1,693,475
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	115	588	121	408	184	365
17. COAL (TON)	36,182	90,829	58,946	32,825	49,854	86,003
18. NATURAL GAS (MCF)	9,027,318	8,122,935	9,620,165	10,225,351	11,410,833	10,516,609
19. SOLAR	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	669	3,427	704	2,376	1,070	2,127
23. COAL	833,193	2,074,833	1,360,675	764,197	1,152,870	1,982,976
24. NATURAL GAS	9,244,078	8,329,906	9,831,194	10,430,648	11,687,186	10,778,573
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	10,077,940	10,408,166	11,192,573	11,197,222	12,841,126	12,763,677
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.01	0.01	0.01	0.01	0.00	0.01
30. COAL	6.31	15.05	8.57	4.29	6.55	10.56
31. NATURAL GAS	87.43	78.31	83.47	86.67	84.32	82.90
32. SOLAR	6.25	6.63	7.95	9.03	9.13	6.53
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT						
35. HEAVY OIL (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL (\$/BBL)	148.10	148.38	148.17	140.61	140.45	140.70
37. COAL (\$/TON)	69.75	82.55	81.43	85.41	77.25	70.52
38. NATURAL GAS (\$/MCF)	3.60	3.88	3.75	3.44	4.05	4.43
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU (\$/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	25.46	25.46	25.47	24.15	24.15	24.14
43. COAL	3.03	3.61	3.53	3.67	3.34	3.06
44. NATURAL GAS	3.52	3.79	3.67	3.37	3.95	4.32
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL (\$/MMBTU)	3.48	3.76	3.65	3.40	3.90	4.13
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	3,758	33,931	6,124	24,752	20,980	25,024
50. COAL	10,019	10,543	10,760	12,063	10,658	11,082
51. NATURAL GAS	8,025	8,137	7,987	8,165	8,387	7,678
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	7,649	7,962	7,589	7,596	7,770	7,537
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	9.57	86.38	15.59	59.76	50.67	60.42
57. COAL	3.03	3.81	3.80	4.43	3.56	3.39
58. NATURAL GAS	2.82	3.08	2.93	2.75	3.32	3.32
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	2.66	2.99	2.77	2.58	3.03	3.11

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

SCHEDULE E3

Estimated							
	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	TOTAL
FUEL COST OF SYSTEM NET GENERATION (\$)							
1. HEAVY OIL	0	0	0	0	0	0	0
2. LIGHT OIL	93,217	92,828	92,445	92,069	45,941	91,513	764,784
3. COAL	5,248,735	5,533,990	4,972,764	1,109,083	952,197	5,503,061	50,861,452
4. NATURAL GAS	54,447,723	56,722,534	53,615,547	52,189,513	48,883,064	45,589,041	539,523,560
5. SOLAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL (\$)	59,789,675	62,349,352	58,680,756	53,390,665	49,881,202	51,183,615	591,149,796
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	0	0	0	0	0	0	0
9. LIGHT OIL	300	300	300	300	150	300	2,276
10. COAL	140,060	155,160	137,900	28,490	25,870	158,610	1,402,956
11. NATURAL GAS	1,507,380	1,530,630	1,445,730	1,395,900	1,258,570	1,249,980	15,869,733
12. SOLAR	148,910	144,090	124,210	123,740	97,710	110,870	1,430,357
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	1,796,650	1,830,180	1,708,140	1,548,430	1,382,300	1,519,760	18,705,322
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	0	0	0	0	0	0	0
16. LIGHT OIL (BBL)	666	666	666	666	333	666	5,444
17. COAL (TON)	74,450	80,160	72,930	15,640	13,950	80,950	692,719
18. NATURAL GAS (MCF)	10,954,655	11,289,625	10,723,105	10,542,335	9,995,638	8,986,635	121,415,204
19. SOLAR	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	0	0	0	0	0	0	0
22. LIGHT OIL	3,900	3,900	3,900	3,900	1,950	3,900	31,824
23. COAL	1,675,180	1,803,630	1,640,900	351,850	313,830	1,821,380	15,775,515
24. NATURAL GAS	11,236,060	11,577,820	10,986,420	10,809,590	10,229,600	9,227,110	124,368,185
25. SOLAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	12,915,140	13,385,350	12,631,220	11,165,340	10,545,380	11,052,390	140,175,523
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.01	0.02	0.01
30. COAL	7.79	8.48	8.07	1.84	1.87	10.43	7.50
31. NATURAL GAS	83.90	83.63	84.64	90.15	91.05	82.25	84.84
32. SOLAR	8.29	7.87	7.27	7.99	7.07	7.30	7.65
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT							
35. HEAVY OIL (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL (\$/BBL)	139.97	139.38	138.81	138.24	137.96	137.41	140.48
37. COAL (\$/TON)	70.50	69.04	68.19	70.91	68.26	67.98	73.42
38. NATURAL GAS (\$/MCF)	4.97	5.02	5.00	4.95	4.89	5.07	4.44
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU (\$/MMBTU)							
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	23.90	23.80	23.70	23.61	23.56	23.46	24.03
43. COAL	3.13	3.07	3.03	3.15	3.03	3.02	3.22
44. NATURAL GAS	4.85	4.90	4.88	4.83	4.78	4.94	4.34
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL (\$/MMBTU)	4.63	4.66	4.65	4.78	4.73	4.63	4.22
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	0	0	0	0	0	0	0
49. LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000	13,982
50. COAL	11,960	11,624	11,899	12,350	12,131	11,483	11,244
51. NATURAL GAS	7,454	7,564	7,599	7,744	8,128	7,382	7,837
52. SOLAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	7,188	7,314	7,395	7,211	7,629	7,272	7,494
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	31.07	30.94	30.82	30.69	30.63	30.50	33.60
57. COAL	3.75	3.57	3.61	3.89	3.68	3.47	3.63
58. NATURAL GAS	3.61	3.71	3.71	3.74	3.88	3.65	3.40
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	3.33	3.41	3.44	3.45	3.61	3.37	3.16

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2021

SCHEDULE A4
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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	201	16.9	-	47.6	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	2,263	15.8	-	38.1	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	155	13.9	-	33.2	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	9,507	18.2	-	45.4	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	9,399	17.0	-	42.5	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	9,153	16.6	-	41.1	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	7,677	17.0	-	42.8	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	6,954	17.1	-	42.3	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	4,448	16.0	-	38.1	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	6,137	16.7	-	41.3	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	9,893	17.8	-	42.9	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	9,643	17.4	-	43.7	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	6,905	15.5	-	38.1	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	82,335	17.0	-	40.5	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL	350	38,985	15.0	34.6	43.3	12,208	GAS	464,311	1,025,000	475,918.6	1,672,133	4.29	3.60
B.B.#3 (COAL)	400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	355	139,271	52.7	78.7	52.7	-	GAS	1,630,571	1,025,000	1,671,335.9	5,872,214	4.22	3.60
BIG BEND #3 TOTAL	355	139,271	52.7	78.7	52.7	12,001	-	-	-	1,671,335.9	5,872,214	4.22	-
B.B.#4 (COAL)	432	84,738	26.4	60.1	57.9	-	COAL	36,182	23,027,843	833,193.4	2,523,735	2.98	69.75
B.B.#4 (GAS)	160	30,218	25.4	60.1	74.4	-	GAS	294,876	1,025,000	302,247.5	1,061,942	3.51	3.60
BIG BEND #4 TOTAL	432	114,956	35.8	60.1	49.8	9,877	-	-	-	1,135,440.9	3,585,677	3.12	-
B.B. IGNITION	-	-	-	-	-	-	GAS	8,709	1,025,000	8,927.0	31,365	-	3.60
BIG BEND CT #4 TOTAL	61	18	0.0	89.4	18.7	67,356	GAS	1,183	1,025,000	1,212.4	4,260	23.67	3.60
BIG BEND STATION TOTAL	1,198	293,230	32.9	59.7	32.9	11,199	-	-	-	3,283,907.9	11,165,649	3.81	-
POLK #1 GASIFIER	220	(1,575)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	180	7,130	4.5	73.4	45.1	11,531	GAS	80,213	1,025,000	82,218.0	288,872	3.02	3.60
POLK #1 ST	50	2,420	5.4	73.4	57.2	-	-	-	-	-	-	-	-
POLK #1 TOTAL	230	7,975	4.7	73.4	47.3	10,308	-	-	-	82,218.0	288,872	3.62	-
POLK #2 ST DUCT FIRING	480	15,997	4.5	-	31.2	8,400	GAS	131,098	1,025,000	134,375.1	472,125	2.95	3.60
POLK #2 ST W/O DUCT FIRING	341	184,554	72.7	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	480	200,551	56.2	99.6	31.2	-	GAS	-	-	134,375.1	472,125	0.24	-
POLK #2 CT (GAS)	180	83,115	62.1	100.0	78.9	10,336	GAS	838,102	1,025,000	859,054.8	3,018,277	3.63	3.60
POLK #2 CT (OIL)	187	151	0.1	100.0	26.9	3,758	LGT.OIL	97	5,829,600	566.7	14,365	9.51	148.09
POLK #2 TOTAL	180	83,266	62.2	100.0	78.9	10,324	-	-	-	859,621.5	3,032,642	3.64	-
POLK #3 CT (GAS)	180	67,245	50.2	100.0	78.7	12,897	GAS	846,130	1,025,000	867,283.4	3,047,188	4.53	3.60
POLK #3 CT (OIL)	187	27	0.0	100.0	10.5	3,758	LGT.OIL	18	5,829,600	102.3	2,666	9.87	148.11
POLK #3 TOTAL	180	67,272	50.2	100.0	78.7	12,894	-	-	-	867,385.7	3,049,854	4.53	-
POLK #4 TOTAL	180	94,597	70.6	99.7	80.8	9,591	GAS	885,172	1,025,000	907,301.4	3,187,790	3.37	3.60
POLK #5 TOTAL	180	92,660	69.2	100.0	80.9	10,602	GAS	958,395	1,025,000	982,355.3	3,451,491	3.72	3.60
POLK #2 CC TOTAL	1,200	538,346	60.3	99.8	60.5	6,968	GAS	-	-	3,751,039.0	13,193,902	2.45	-
POLK STATION TOTAL	1,430	546,321	51.4	95.6	51.5	7,016	-	-	-	3,833,256.9	13,482,774	2.47	-

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	243	0	0.0	81.0	0.0	-		-	-	-	-	-	-
BAYSIDE CT1A	183	0	0.0	81.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE CT1B	183	0	0.0	81.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE CT1C	183	0	0.0	80.7	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE UNIT 1 TOTAL	792	0	0.0	81.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE ST 2	315	140,820	60.1	97.8	60.1	-		-	-	-	-	-	-
BAYSIDE CT2A	(3) 183	84,419	62.0	100.0	65.6	11,433	GAS	941,876	1,025,000	965,423.9	3,390,660	4.02	3.60
BAYSIDE CT2B	(3) 183	73,077	53.7	100.0	65.5	11,767	GAS	839,222	1,025,000	860,203.3	3,021,115	4.13	3.60
BAYSIDE CT2C	(3) 183	46,034	33.8	96.5	65.6	11,735	GAS	527,312	1,025,000	540,495.6	1,898,271	4.12	3.60
BAYSIDE CT2D	(3) 183	49,686	36.5	97.9	66.0	11,602	GAS	562,656	1,025,000	576,723.6	2,025,505	4.08	3.60
BAYSIDE UNIT 2 TOTAL	1,047	394,036	50.6	98.4	50.6	7,466	GAS	2,871,066	1,025,000	2,942,846.4	10,335,551	2.62	3.60
BAYSIDE UNIT 3 TOTAL	61	0	0.0	98.7	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE UNIT 4 TOTAL	61	703	1.6	100.0	88.4	10,876	GAS	7,459	1,025,000	7,645.7	26,863	3.82	3.60
BAYSIDE UNIT 5 TOTAL	61	672	1.5	100.0	88.3	10,448	GAS	6,848	1,025,000	7,018.8	24,660	3.67	3.60
BAYSIDE UNIT 6 TOTAL	61	294	0.7	100.0	84.1	11,094	GAS	3,185	1,025,000	3,264.4	11,469	3.90	3.60
BAYSIDE STATION TOTAL	2,083	395,705	25.5	91.9	25.5	7,479	GAS	2,888,558	1,025,000	2,960,775.3	10,398,543	2.63	3.60
SYSTEM	5,363	1,317,591	33.0	84.8	35.6	7,648	-	-	-	10,077,940.1	35,046,966	2.66	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

CC = COMBINED CYCLE
ST = STEAM TURBINE

Footnotes:
(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) Consists of prior month adjustments, details on Schedule A5, page 2.

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2021

SCHEDULE A4
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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	217	19.5	-	52.6	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	2,582	19.2	-	45.5	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	164	15.7	-	36.3	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	8,177	16.8	-	48.2	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	10,354	20.0	-	48.5	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	9,931	19.2	-	46.6	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	8,318	19.7	-	48.5	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	7,584	19.9	-	48.7	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	4,804	18.5	-	42.1	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	6,769	19.7	-	47.7	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	10,287	19.8	-	46.1	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	10,301	19.9	-	47.6	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	7,164	17.2	-	41.9	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	86,652	19.1	-	43.6	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL	350	109,228	46.4	100.0	46.4	12,243	GAS	1,303,381	464,311	1,337,268.7	5,060,820	4.63	3.88
B.B.#3 (COAL)	400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	355	24,732	10.4	99.2	58.7	-	GAS	275,602	1,630,572	282,767.8	1,070,119	4.33	3.88
BIG BEND #3 TOTAL	355	24,732	10.4	99.2	58.7	11,433	-	-	-	282,767.8	1,070,119	4.33	-
B.B.#4 (COAL)	432	198,395	66.0	98.4	77.6	-	COAL	90,829	36,182	2,074,832.8	7,513,270	3.79	82.72
B.B.#4 (GAS)	160	14,071	12.6	98.4	91.6	-	GAS	145,377	294,876	149,157.2	564,477	4.01	3.88
BIG BEND #4 TOTAL	432	212,466	70.7	98.4	75.3	10,468	-	-	-	2,223,990.0	8,077,747	3.80	-
B.B. IGNITION	-	-	-	-	-	-	GAS	4,118	8,709	4,225.0	15,989	-	3.88
BIG BEND CT #4 TOTAL	61	812	1.9	100.0	81.4	14,234	GAS	11,265	1,183	11,557.7	43,740	5.39	3.88
BIG BEND STATION TOTAL	1,198	347,238	43.1	99.2	43.1	11,104	-	-	-	3,855,584.2	14,268,415	4.11	-
POLK #1 GASIFIER	220	(1,606)	-	-	-	-	COAL	-	-	-	(14,964)	0.93	-
POLK #1 CT (GAS)	180	6,714	4.6	99.9	48.3	13,123	GAS	85,870	80,213	88,103.0	333,421	3.69	3.88
POLK #1 ST	50	2,324	5.7	99.9	63.6	-	-	-	-	-	-	-	-
POLK #1 TOTAL	230	7,432	4.8	99.9	50.9	11,856	-	-	-	88,103.0	318,457	4.28	-
POLK #2 ST DUCT FIRING	480	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
POLK #2 ST W/O DUCT FIRING	341	(616)	0.0	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	480	(616)	(0.2)	67.9	0.0	-	GAS	-	-	0.0	0	0.00	-
POLK #2 CT (GAS)	180	4,615	3.8	94.8	60.5	12,570	GAS	56,540	838,102	58,009.7	219,534	4.76	3.88
POLK #2 CT (OIL)	187	76	0.1	94.8	21.5	34,083	LGT.OIL	443	97	2,584.2	65,730	86.49	148.37
POLK #2 TOTAL	180	4,691	3.9	94.8	60.5	12,917	-	-	-	60,593.8	285,264	6.08	-
POLK #3 CT (GAS)	180	4,424	3.7	94.9	60.6	12,737	GAS	54,911	846,130	56,338.8	213,211	4.82	3.88
POLK #3 CT (OIL)	187	25	0.0	94.9	19.4	34,083	LGT.OIL	145	18	842.7	21,515	86.06	148.38
POLK #3 TOTAL	180	4,449	3.7	94.9	60.6	12,856	-	-	-	57,181.5	234,726	5.28	-
POLK #4 TOTAL	180	2,187	1.8	100.0	56.5	13,289	GAS	28,324	885,172	29,060.9	109,980	5.03	3.88
POLK #5 TOTAL	180	3,200	2.7	100.0	66.2	12,223	GAS	38,120	958,395	39,110.7	148,012	4.63	3.88
POLK #2 CC TOTAL	1,200	13,911	1.7	85.6	26.9	13,368	GAS	-	-	185,946.9	777,982	5.59	-
POLK STATION TOTAL	1,430	21,343	2.2	87.9	23.5	12,841	-	-	-	274,049.9	1,096,439	5.14	-

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	243	123,939	75.9	97.5	76.5	-		-	-	-	-	-	-
BAYSIDE CT1A	183	79,230	64.4	100.0	71.9	11,384	GAS	879,113	0	901,970.1	3,413,455	4.31	3.88
BAYSIDE CT1B	183	80,910	65.8	100.0	71.9	11,376	GAS	897,097	0	920,421.1	3,483,284	4.31	3.88
BAYSIDE CT1C	183	72,538	59.0	91.7	71.6	11,125	GAS	786,527	0	806,976.4	3,053,958	4.21	3.88
BAYSIDE UNIT 1 TOTAL	792	356,617	67.0	97.3	67.5	7,373	GAS	2,562,737	0	2,629,367.6	9,950,697	2.79	3.88
BAYSIDE ST 2	315	170,426	80.5	99.6	80.5	-		-	-	-	-	-	-
BAYSIDE CT2A	183	82,529	64.8	100.0	73.3	11,036	GAS	887,737	941,593	910,817.8	3,446,940	4.18	3.88
BAYSIDE CT2B	183	87,360	71.0	100.0	72.7	11,331	GAS	964,767	838,938	989,850.8	3,746,036	4.29	3.88
BAYSIDE CT2C	183	75,733	61.6	98.4	73.1	11,306	GAS	834,501	527,028	856,198.2	3,240,235	4.28	3.88
BAYSIDE CT2D	183	77,017	62.6	100.0	72.7	11,256	GAS	844,922	562,373	866,889.8	3,280,697	4.26	3.88
BAYSIDE UNIT 2 TOTAL	1,047	493,065	70.1	99.6	70.1	7,349	GAS	3,531,927	2,869,932	3,623,756.6	13,713,908	2.78	3.88
BAYSIDE UNIT 3 TOTAL	61	174	0.4	100.0	73.1	11,152	GAS	1,886	0	1,935.4	7,325	4.21	3.88
BAYSIDE UNIT 4 TOTAL	61	313	0.8	100.0	84.8	10,826	GAS	3,306	7,459	3,392.5	12,839	4.10	3.88
BAYSIDE UNIT 5 TOTAL	61	1,087	2.7	98.8	84.7	10,732	GAS	11,366	6,848	11,661.1	44,131	4.06	3.88
BAYSIDE UNIT 6 TOTAL	61	767	1.9	98.5	83.5	10,983	GAS	8,205	3,185	8,418.5	31,859	4.15	3.88
BAYSIDE STATION TOTAL	2,083	852,023	60.9	98.7	60.9	7,369	GAS	6,119,427	2,887,424	6,278,531.7	23,760,759	2.79	3.88
SYSTEM	5,363	1,307,256	35.0	95.5	52.4	7,962	-	-	-	10,408,165.8	39,125,613	2.99	-

LEGEND:

B.B. = BIG BEND
CT = COMBUSTION TURBINE

CC = COMBINED CYCLE
ST = STEAM TURBINE

Footnotes:

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ Consists of fixed costs and aerial survey adjustment.

⁽⁴⁾ Polk's portion of the aerial survey adjustment

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2021

SCHEDULE A4
PAGE 1 OF 2

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	291	24.5	-	70.5	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	3,760	26.2	-	66.3	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	227	20.4	-	50.3	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	5,883	11.3	-	34.7	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	14,705	26.7	-	68.8	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	14,189	25.7	-	66.5	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	11,883	26.3	-	69.3	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	10,626	26.1	-	68.3	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	6,919	24.9	-	60.7	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	9,440	25.7	-	66.6	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	15,790	28.4	-	70.7	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	14,229	25.8	-	65.8	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	9,339	21.0	-	54.6	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	117,281	24.2	-	59.0	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL	350	57,278	22.0	79.0	46.4	12,683	GAS	709,430	1,024,000	726,456.7	2,659,698	4.64	3.75
B.B.#3 (COAL)	400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	355	40,858	15.5	100.0	57.6	-	GAS	480,042	1,024,000	491,563.0	1,799,706	4.40	3.75
BIG BEND #3 TOTAL	355	40,858	15.5	100.0	57.6	12,031	-	-	-	491,563.0	1,799,706	4.40	-
B.B.#4 (COAL)	432	128,065	39.9	86.5	66.3	-	COAL	58,946	23,083,410	1,360,674.7	4,799,736	3.75	81.43
B.B.#4 (GAS)	160	31,366	26.4	86.5	95.2	-	GAS	330,596	1,024,000	338,530.3	1,239,424	3.95	3.75
BIG BEND #4 TOTAL	432	159,431	49.7	86.5	57.4	10,658	-	-	-	1,699,205.0	6,039,160	3.79	-
B.B. IGNITION	-	-	-	-	-	-	GAS	19,390	1,024,000	19,855.3	72,694	-	3.75
BIG BEND CT #4 TOTAL	61	820	1.8	100.0	77.5	14,205	GAS	11,375	1,024,000	11,647.9	42,645	5.20	3.75
BIG BEND STATION TOTAL	1,198	258,387	29.0	89.0	33.6	11,335	-	-	-	2,928,872.6	10,613,903	4.11	-
POLK #1 GASIFIER	220	(1,611)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	180	34,663	25.1	90.9	54.2	12,609	GAS	426,804	1,024,000	437,047.4	1,600,114	3.24	3.75
POLK #1 ST	50	14,719	38.3	95.5	84.1	-	-	-	-	-	-	-	-
POLK #1 TOTAL	230	47,771	27.9	91.9	60.5	9,149	-	-	-	437,047.4	1,600,114	3.35	-
POLK #2 ST DUCT FIRING	480	7,379	2.1	-	0.0	8,400	GAS	60,533	1,024,000	61,985.7	226,941	3.08	3.75
POLK #2 ST W/O DUCT FIRING	341	104,827	41.4	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	480	112,206	31.5	53.3	0.0	-	GAS	-	-	61,985.7	226,941	0.20	-
POLK #2 CT (GAS)	180	58,498	43.7	99.9	75.3	11,390	GAS	650,701	1,024,000	666,317.3	2,439,515	4.17	3.75
POLK #2 CT (OIL)	187	48	0.0	99.9	21.7	6,127	LGT.OIL	50	5,829,600	291.2	7,409	15.44	148.18
POLK #2 TOTAL	180	58,546	43.8	99.9	75.3	11,386	-	-	-	666,608.5	2,446,924	4.18	-
POLK #3 CT (GAS)	180	60,672	45.4	100.0	76.6	11,392	GAS	674,957	1,024,000	691,156.4	2,530,456	4.17	3.75
POLK #3 CT (OIL)	187	67	0.0	100.0	26.4	6,127	LGT.OIL	71	5,829,600	413.0	10,520	15.70	148.17
POLK #3 TOTAL	180	60,739	45.4	100.0	76.6	11,386	-	-	-	691,569.4	2,540,976	4.18	-
POLK #4 TOTAL	180	33,906	25.4	70.6	76.8	11,211	GAS	371,211	1,024,000	380,120.6	1,391,694	4.10	3.75
POLK #5 TOTAL	180	52,408	39.2	100.0	78.4	11,091	GAS	567,629	1,024,000	581,251.6	2,128,073	4.06	3.75
POLK #2 CC TOTAL	1,200	317,805	35.6	76.9	59.3	7,494	GAS	-	-	2,381,535.8	8,734,608	2.75	-
POLK STATION TOTAL	1,430	365,576	34.4	79.3	57.3	7,710	-	-	-	2,818,583.2	10,334,722	2.83	-

(3)

SCHEDULE A4
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	243	98,363	54.5	68.7	55.8	-		-	-	-	-	-	-
BAYSIDE CT1A	183	43,961	32.3	45.1	71.7	11,409	GAS	489,792	1,024,000	501,546.6	1,836,260	4.18	3.75
BAYSIDE CT1B	183	65,315	48.0	72.5	68.9	11,564	GAS	737,599	1,024,000	755,301.2	2,765,303	4.23	3.75
BAYSIDE CT1C	183	73,555	54.1	98.3	69.0	11,283	GAS	810,462	1,024,000	829,913.5	3,038,471	4.13	3.75
BAYSIDE UNIT 1 TOTAL	792	281,194	47.7	71.0	49.0	7,421	GAS	2,037,853	1,024,000	2,086,761.3	7,640,034	2.72	3.75
BAYSIDE ST 2	315	156,959	67.1	97.3	67.1	-		-	-	-	-	-	-
BAYSIDE CT2A	183	76,481	56.2	89.0	69.6	11,233	GAS	838,988	1,024,000	859,123.9	3,145,417	4.11	3.75
BAYSIDE CT2B	183	89,654	65.9	100.0	70.0	11,464	GAS	1,003,676	1,024,000	1,027,764.4	3,762,843	4.20	3.75
BAYSIDE CT2C	183	66,623	49.0	100.0	71.2	11,413	GAS	742,534	1,024,000	760,354.8	2,783,805	4.18	3.75
BAYSIDE CT2D	183	59,777	44.0	100.0	71.2	11,361	GAS	663,210	1,024,000	679,126.8	2,486,413	4.16	3.75
BAYSIDE UNIT 2 TOTAL	1,047	449,494	57.7	97.3	57.8	7,400	GAS	3,248,408	1,024,000	3,326,369.9	12,178,478	2.71	3.75
BAYSIDE UNIT 3 TOTAL	61	485	1.1	92.9	87.0	10,818	GAS	5,128	1,024,000	5,251.0	19,225	3.96	3.75
BAYSIDE UNIT 4 TOTAL	61	1,197	2.6	100.0	87.4	10,728	GAS	12,536	1,024,000	12,836.8	46,998	3.93	3.75
BAYSIDE UNIT 5 TOTAL	61	597	1.3	100.0	83.9	12,091	GAS	7,047	1,024,000	7,216.3	26,420	4.43	3.75
BAYSIDE UNIT 6 TOTAL	61	614	1.4	100.0	87.0	10,878	GAS	6,525	1,024,000	6,681.7	24,463	3.98	3.75
BAYSIDE STATION TOTAL	2,083	733,581	47.3	87.4	47.4	7,423	GAS	5,317,497	1,024,000	5,445,117.0	19,935,618	2.72	3.75
SYSTEM	5,363	1,474,825	35.8	85.4	46.7	7,589	-	-	-	11,192,572.8	40,884,243	2.77	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

Footnotes:
⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ Consists of prior month adjustments, details on Schedule A5, page 2.

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	298	25.9	-	55.8	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	4,092	29.4	-	59.2	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	205	19.0	-	45.9	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	15,220	30.2	-	61.5	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	14,921	27.9	-	57.0	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	15,635	29.2	-	59.6	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	12,914	29.5	-	60.5	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	11,625	29.5	-	60.4	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	7,552	28.0	-	55.6	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	10,028	28.2	-	58.0	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	15,571	29.0	-	59.1	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	14,061	26.3	-	54.2	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	10,998	25.5	-	52.2	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	133,120	28.3	-	56.2	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL	340	71,829	29.3	72.0	41.0	13,106	GAS	921,110	1,022,000	941,374.8	3,168,931	4.41	3.44
B.B.#3 (COAL)	395	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	345	114,843	46.2	81.5	56.8	-	GAS	1,362,779	1,022,000	1,392,760.3	4,688,420	4.08	3.44
BIG BEND #3 TOTAL	345	114,843	46.2	81.5	56.8	12,128	-	-	-	1,392,760.3	4,688,420	4.08	-
B.B.#4 (COAL)	422	64,334	21.2	33.2	65.7	-	COAL	32,825	23,280,954	764,197.3	2,803,672	4.36	85.41
B.B.#4 (GAS)	155	14,274	12.8	33.2	29.3	-	GAS	168,486	1,022,000	172,192.2	579,647	4.06	3.44
BIG BEND #4 TOTAL	422	78,608	25.9	33.2	59.3	11,912	-	-	-	936,389.5	3,383,319	4.30	-
B.B. IGNITION	-	-	-	-	-	-	GAS	19,238	1,022,000	19,661.5	66,186	-	3.44
BIG BEND CT #4 TOTAL	56	95	0.2	100.0	53.3	26,726	GAS	2,484	1,022,000	2,539.0	8,547	9.00	3.44
BIG BEND STATION TOTAL	1,163	265,375	31.7	62.1	38.9	12,336	-	-	-	3,273,063.6	11,315,403	4.26	-
POLK #1 GASIFIER	220	(986)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	152	33,353	29.8	87.1	68.8	12,157	GAS	396,736	1,022,000	405,464.5	1,364,907	2.91	3.44
POLK #1 ST	50	13,617	37.0	94.1	88.3	-	-	-	-	-	-	-	-
POLK #1 TOTAL	202	45,984	31.6	88.9	72.9	8,818	-	-	-	405,464.5	1,364,907	2.97	-
POLK #2 ST DUCT FIRING	461	7,295	2.2	-	16.2	8,400	GAS	59,962	1,022,000	61,281.5	206,291	2.83	3.44
POLK #2 ST W/O DUCT FIRING	322	162,245	70.0	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	461	169,540	51.1	78.2	16.2	-	GAS	-	-	61,281.5	206,291	0.12	-
POLK #2 CT (GAS)	150	91,776	85.0	100.0	94.0	11,079	GAS	994,933	1,022,000	1,016,822.0	3,422,907	3.73	3.44
POLK #2 CT (OIL)	159	44	0.0	100.0	30.6	24,789	LGT.OIL	186	5,829,600	1,086.0	26,154	59.44	140.61
POLK #2 TOTAL	150	91,820	85.0	100.0	94.0	11,086	-	-	-	1,017,908.0	3,449,061	3.76	-
POLK #3 CT (GAS)	150	92,448	85.7	100.0	92.9	11,167	GAS	1,010,179	1,022,000	1,032,403.3	3,475,358	3.76	3.44
POLK #3 CT (OIL)	159	52	0.0	100.0	36.4	24,789	LGT.OIL	222	5,829,600	1,290.2	31,216	60.03	140.61
POLK #3 TOTAL	150	92,500	85.7	100.0	92.9	11,175	-	-	-	1,033,693.5	3,506,574	3.79	-
POLK #4 TOTAL	150	12,791	11.8	15.1	95.4	10,963	GAS	137,216	1,022,000	140,234.8	472,069	3.69	3.44
POLK #5 TOTAL	150	87,564	81.1	89.9	95.3	10,841	GAS	928,870	1,022,000	949,304.9	3,195,626	3.65	3.44
POLK #2 CC TOTAL	1,061	454,215	59.5	77.1	59.5	7,050	GAS	-	-	3,202,422.7	10,829,621	2.38	-
POLK STATION TOTAL	1,263	500,199	55.0	78.9	55.0	7,213	-	-	-	3,607,887.2	12,194,528	2.44	-

SCHEDULE A4
PAGE 2 OF 2

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	233	90,023	53.7	89.2	54.3	-		-	-	-	-	-	-
BAYSIDE CT1A	156	52,268	46.5	94.8	75.0	11,878	GAS	607,474	1,022,000	620,838.2	2,089,916	4.00	3.44
BAYSIDE CT1B	156	62,842	56.0	100.0	76.8	11,766	GAS	723,473	1,022,000	739,389.6	2,488,992	3.96	3.44
BAYSIDE CT1C	156	46,882	41.7	76.0	77.8	11,429	GAS	524,269	1,022,000	535,803.0	1,803,662	3.85	3.44
BAYSIDE UNIT 1 TOTAL	701	252,015	49.9	89.9	50.5	7,524	GAS	1,855,216	1,022,000	1,896,030.8	6,382,570	2.53	3.44
BAYSIDE ST 2	305	113,993	51.9	96.6	51.9	-		-	-	-	-	-	-
BAYSIDE CT2A	156	86,458	77.0	100.0	77.0	11,446	GAS	968,341	1,022,000	989,643.3	3,331,418	3.85	3.44
BAYSIDE CT2B	156	54,392	48.4	85.6	77.4	11,636	GAS	619,294	1,022,000	632,918.8	2,130,581	3.92	3.44
BAYSIDE CT2C	156	38,762	34.5	100.0	79.0	11,624	GAS	440,888	1,022,000	450,587.6	1,516,803	3.91	3.44
BAYSIDE CT2D	156	28,466	25.3	100.0	77.9	11,668	GAS	324,999	1,022,000	332,148.7	1,118,105	3.93	3.44
BAYSIDE UNIT 2 TOTAL	929	322,071	48.2	96.5	48.2	7,468	GAS	2,353,522	1,022,000	2,405,298.5	8,096,907	2.51	3.44
BAYSIDE UNIT 3 TOTAL	56	187	0.5	90.4	82.0	11,385	GAS	2,082	1,022,000	2,128.3	7,164	3.83	3.44
BAYSIDE UNIT 4 TOTAL	56	395	1.0	76.5	86.3	11,345	GAS	4,389	1,022,000	4,485.4	15,099	3.82	3.44
BAYSIDE UNIT 5 TOTAL	56	328	0.8	77.8	80.6	11,604	GAS	3,725	1,022,000	3,806.9	12,815	3.91	3.44
BAYSIDE UNIT 6 TOTAL	56	392	1.0	84.5	85.1	11,544	GAS	4,424	1,022,000	4,520.9	15,219	3.88	3.44
BAYSIDE STATION TOTAL	1,854	575,388	43.1	92.3	43.1	7,501	GAS	4,223,358	1,022,000	4,316,270.7	14,529,774	2.53	3.44
SYSTEM	4,932	1,474,082	38.2	80.1	46.6	7,596	-	-	-	11,197,221.6	38,039,705	2.58	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

Footnotes:
(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2021

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	331	27.8	-	86.6	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	4,486	31.2	-	93.0	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	197	17.7	-	49.2	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	16,634	31.9	-	94.9	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	17,352	31.4	-	93.5	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	18,267	33.0	-	98.0	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	14,552	32.2	-	95.4	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	12,934	31.7	-	93.7	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	8,562	30.8	-	86.7	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	10,264	27.9	-	92.3	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	17,972	32.3	-	93.3	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	16,157	29.2	-	86.6	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	13,159	29.6	-	90.9	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	150,867	27.9	-	92.3	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND 5 CT	(3)	(32)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND 6 CT	(3)	(111)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #1 CC TOTAL	0	(143)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	-
BIG BEND #2 TOTAL	340	102,472	40.5	64.7	40.8	12,919	GAS	1,291,516	1,025,000	1,323,803.7	5,229,472	5.10	4.05
B.B.#3 (COAL)	395	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	345	134,509	52.4	81.2	52.4	-	GAS	1,618,416	1,025,000	1,658,876.9	6,553,124	4.87	4.05
BIG BEND #3 TOTAL	345	134,509	52.4	81.2	52.4	12,333	-	-	-	1,658,876.9	6,553,124	4.87	-
B.B.#4 (COAL)	422	108,630	34.6	57.1	46.2	-	COAL	49,854	23,124,927	1,152,870.1	3,851,041	3.55	77.25
B.B.#4 (GAS)	155	43,225	37.5	57.1	60.2	-	GAS	455,517	1,025,000	466,904.8	1,844,432	4.27	4.05
BIG BEND #4 TOTAL	422	151,855	48.4	57.1	61.0	10,667	-	-	-	1,619,774.9	5,695,473	3.75	-
B.B. IGNITION	-	-	-	-	-	-	GAS	8,701	1,025,000	8,918.9	35,233	-	4.05
BIG BEND CT #4 TOTAL	56	107	0.3	100.0	57.0	20,008	GAS	2,089	0	2,140.9	8,457	7.90	4.05
BIG BEND STATION TOTAL	1,163	388,800	45.0	68.5	45.0	11,843	-	-	-	4,604,596.3	17,521,759	4.51	-
POLK #1 GASIFIER	220	(462)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	152	48,460	42.6	58.4	72.9	11,878	GAS	561,554	1,025,000	575,593.1	2,273,787	3.33	4.05
POLK #1 ST	50	19,824	52.9	58.4	90.7	-	-	-	-	-	-	-	-
POLK #1 TOTAL	202	67,822	45.1	58.4	77.3	8,487	-	-	-	575,593.1	2,273,787	3.35	-
POLK #2 ST DUCT FIRING	461	6,253	1.8	-	18.9	8,400	GAS	51,240	1,025,000	52,521.1	207,476	3.32	4.05
POLK #2 ST W/O DUCT FIRING	322	181,577	75.8	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	461	187,830	54.8	85.3	18.9	-	GAS	-	-	52,521.1	207,476	0.11	-
POLK #2 CT (GAS)	150	50,657	45.4	60.1	89.7	11,241	GAS	555,543	1,025,000	569,431.9	2,249,448	4.44	4.05
POLK #2 CT (OIL)	159	21	0.0	60.1	14.7	20,685	LGT.OIL	76	5,829,600	444.3	10,674	50.83	140.45
POLK #2 TOTAL	150	50,678	45.4	60.1	89.7	11,245	-	-	-	569,876.2	2,260,122	4.46	-
POLK #3 CT (GAS)	150	87,268	78.2	93.8	89.7	11,297	GAS	961,783	1,025,000	985,827.7	3,894,353	4.46	4.05
POLK #3 CT (OIL)	159	30	0.0	93.8	23.9	20,685	LGT.OIL	108	5,829,600	626.1	15,168	50.56	140.44
POLK #3 TOTAL	150	87,298	78.2	93.8	89.7	11,300	-	-	-	986,453.8	3,909,521	4.48	-
POLK #4 TOTAL	150	93,103	83.4	100.0	92.7	10,930	GAS	992,822	1,025,000	1,017,642.8	4,020,033	4.32	4.05
POLK #5 TOTAL	150	85,068	76.2	93.6	92.0	10,947	GAS	908,537	1,025,000	931,250.4	3,678,754	4.32	4.05
POLK #2 CC TOTAL	1,061	503,977	63.8	86.2	64.1	7,059	GAS	-	-	3,557,744.3	14,075,906	2.79	-
POLK STATION TOTAL	1,263	571,799	60.9	81.8	61.1	7,229	-	-	-	4,133,337.4	16,349,693	2.86	-

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	233	85,157	49.1	89.6	54.4	-		-	-	-	-	-	-
BAYSIDE CT1A	156	44,631	38.5	97.0	74.1	11,939	GAS	519,843	1,025,000	532,838.8	2,104,894	4.72	4.05
BAYSIDE CT1B	156	55,178	47.5	98.1	74.6	11,895	GAS	640,336	1,025,000	656,344.5	2,592,782	4.70	4.05
BAYSIDE CT1C	156	53,072	45.7	100.0	73.7	11,647	GAS	603,031	1,025,000	618,106.4	2,441,730	4.60	4.05
BAYSIDE UNIT 1 TOTAL	701	238,038	45.6	95.5	50.6	7,592	GAS	1,763,210	1,025,000	1,807,289.8	7,139,406	3.00	4.05
BAYSIDE ST 2	305	107,322	47.3	83.6	47.3	-		-	-	-	-	-	-
BAYSIDE CT2A	156	55,425	47.8	78.1	75.0	11,571	GAS	625,708	1,025,000	641,350.4	2,533,551	4.57	4.05
BAYSIDE CT2B	156	50,770	43.7	78.6	75.4	11,696	GAS	579,317	1,025,000	593,799.6	2,345,709	4.62	4.05
BAYSIDE CT2C	156	46,338	39.9	100.0	75.8	11,798	GAS	533,341	1,025,000	546,674.7	2,159,550	4.66	4.05
BAYSIDE CT2D	156	43,058	37.1	78.4	73.9	11,864	GAS	498,382	1,025,000	510,841.4	2,017,997	4.69	4.05
BAYSIDE UNIT 2 TOTAL	929	302,913	43.8	83.7	43.8	7,569	GAS	2,236,747	1,025,000	2,292,666.1	9,056,807	2.99	4.05
BAYSIDE UNIT 3 TOTAL	56	0	0.0	100.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE UNIT 4 TOTAL	56	138	0.3	98.9	64.2	14,964	GAS	2,022	1,025,000	2,072.6	8,187	5.93	4.05
BAYSIDE UNIT 5 TOTAL	56	78	0.2	99.0	65.0	15,018	GAS	1,136	1,025,000	1,163.9	4,598	5.89	4.05
BAYSIDE UNIT 6 TOTAL	56	0	0.0	97.9	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE STATION TOTAL	1,854	541,167	39.2	90.0	39.2	7,582	GAS	4,003,115	1,025,000	4,103,192.4	16,208,998	3.00	4.05
SYSTEM	4,932	1,652,633	45.0	81.7	49.3	7,770	-	-	-	12,841,126.1	50,080,450	3.03	-

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE

Footnotes:
⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ Station Service

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
TIA SOLAR	1.6	265	23.0	-	49.0	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.3	3,150	22.7	-	41.4	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	183	16.9	-	31.4	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.1	12,162	24.1	-	47.0	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.2	13,403	25.1	-	48.3	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.3	13,403	25.1	-	47.7	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	60.8	10,766	24.6	-	47.6	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	54.8	9,321	23.6	-	46.0	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.4	6,254	23.2	-	41.7	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR	49.4	8,239	23.2	-	45.6	-	SOLAR	-	-	-	-	-	-
WIMAUMA SOLAR	74.7	13,137	24.4	-	44.6	-	SOLAR	-	-	-	-	-	-
LITTLE MANATEE RIVER SOLAR	74.3	10,731	20.1	-	39.0	-	SOLAR	-	-	-	-	-	-
DURRANCE	59.8	9,558	22.2	-	44.8	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	652.2	110,572	23.2	-	45.6	-	SOLAR	-	-	-	-	-	-
BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND 5 CT	(3) 0	(89)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND 6 CT	(3) 0	(136)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BIG BEND #1 CC TOTAL	0	(225)	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	-
BIG BEND #2 TOTAL	340	24,423	10.0	69.3	42.5	12,733	GAS	303,398	1,025,000	310,983.2	1,342,417	5.50	4.42
B.B.#3 (COAL)	395	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
B.B.#3 (GAS)	345	99,833	40.2	60.0	54.4	-	GAS	1,186,154	1,025,000	1,215,807.8	5,246,297	5.26	4.42
BIG BEND #3 TOTAL	345	99,833	40.2	60.0	54.4	12,178	-	-	-	1,215,807.8	5,246,297	5.26	-
B.B.#4 (COAL)	422	180,558	59.4	82.2	60.6	-	COAL	86,003	23,057,060	1,982,976.3	6,065,132	3.36	70.52
B.B.#4 (GAS)	155	2,564	2.3	82.2	35.2	-	GAS	27,823	1,025,000	28,518.2	124,319	4.85	4.47
BIG BEND #4 TOTAL	422	183,122	60.3	82.2	60.3	10,984	-	-	-	2,011,494.5	6,189,451	3.38	-
B.B. IGNITION	-	-	-	-	-	-	GAS	928	1,025,000	951.7	1,730	-	1.86
BIG BEND CT #4 TOTAL	56	250	0.6	100.0	68.7	16,217	GAS	3,955	0	4,054.2	17,493	7.00	4.42
BIG BEND STATION TOTAL	1,163	307,403	36.7	72.7	36.7	11,523	-	-	-	3,542,339.6	12,797,388	4.16	-
POLK #1 GASIFIER	220	(1,614)	-	-	-	-	COAL	-	-	-	-	-	-
POLK #1 CT (GAS)	152	(354)	(0.9)	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
POLK #1 ST	50	(599)	(4.5)	0.0	0.0	-	-	-	-	-	-	-	-
POLK #1 TOTAL	202	(2,567)	(1.8)	0.0	0.0	0	-	-	-	0.0	0	0.00	-
POLK #2 ST DUCT FIRING	461	8,287	2.5	-	20.6	8,400	GAS	67,910	1,025,000	69,607.6	300,334	3.62	4.42
POLK #2 ST W/O DUCT FIRING	322	210,062	90.6	-	-	-	-	-	-	-	-	-	-
POLK #2 ST TOTAL	461	218,349	65.8	100.0	20.6	-	GAS	-	-	69,607.6	300,334	0.14	-
POLK #2 CT (GAS)	150	84,607	78.3	99.8	91.3	11,256	GAS	929,075	1,025,000	952,301.7	4,108,874	4.86	4.42
POLK #2 CT (OIL)	159	19	0.0	99.8	33.5	24,975	LGT.OIL	80	5,829,600	466.2	11,256	59.24	140.70
POLK #2 TOTAL	150	84,626	78.4	99.8	91.3	11,259	-	-	-	952,767.9	4,120,130	4.87	-
POLK #3 CT (GAS)	150	73,447	68.1	77.9	92.7	11,175	GAS	800,762	1,025,000	820,780.9	3,541,405	4.82	4.42
POLK #3 CT (OIL)	159	66	0.1	77.9	26.6	24,975	LGT.OIL	285	5,829,600	1,660.8	40,098	60.75	140.69
POLK #3 TOTAL	150	73,513	68.1	77.9	92.7	11,188	-	-	-	822,441.8	3,581,503	4.87	-
POLK #4 TOTAL	150	99,391	92.0	99.1	92.9	10,971	GAS	1,063,869	1,025,000	1,090,465.6	4,705,007	4.73	4.42
POLK #5 TOTAL	150	99,578	92.2	100.0	93.4	10,929	GAS	1,061,707	1,025,000	1,088,250.2	4,695,448	4.72	4.42
POLK #2 CC TOTAL	1,061	575,457	75.3	96.7	75.3	6,992	GAS	-	-	4,023,533.0	17,402,422	3.02	-
POLK STATION TOTAL	1,263	572,890	63.0	81.2	63.0	7,023	-	-	-	4,023,533.0	17,402,422	3.04	-

SCHEDULE A4
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP- ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
BAYSIDE ST 1	233	94,726	56.5	83.8	66.8	-		-	-	-	-	-	-
BAYSIDE CT1A	156	55,953	49.8	91.8	75.1	11,825	GAS	645,523	1,025,000	661,661.4	2,863,891	5.12	4.44
BAYSIDE CT1B	156	59,406	52.9	97.3	76.0	11,769	GAS	682,117	1,025,000	699,169.7	3,026,242	5.09	4.44
BAYSIDE CT1C	156	51,369	45.7	95.2	74.6	11,545	GAS	578,581	1,025,000	593,045.4	2,566,900	5.00	4.44
BAYSIDE UNIT 1 TOTAL	701	261,454	51.8	91.1	61.3	7,473	GAS	1,906,221	1,025,000	1,953,876.5	8,457,033	3.23	4.44
BAYSIDE ST 2	305	158,473	72.2	94.8	72.2	-		-	-	-	-	-	-
BAYSIDE CT2A	156	81,371	72.4	100.0	77.6	11,333	GAS	899,664	1,025,000	922,155.5	3,991,398	4.91	4.44
BAYSIDE CT2B	156	81,747	72.8	100.0	77.9	11,475	GAS	915,190	1,025,000	938,069.4	4,060,279	4.97	4.44
BAYSIDE CT2C	156	57,327	51.0	79.3	77.9	11,585	GAS	647,928	1,025,000	664,126.4	2,874,562	5.01	4.44
BAYSIDE CT2D	156	61,738	55.0	100.0	77.7	11,543	GAS	695,287	1,025,000	712,668.9	3,084,670	5.00	4.44
BAYSIDE UNIT 2 TOTAL	929	440,656	65.9	94.8	65.9	7,346	GAS	3,158,068	1,025,000	3,237,020.2	14,010,909	3.18	4.44
BAYSIDE UNIT 3 TOTAL	56	0	0.0	100.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE UNIT 4 TOTAL	56	62	0.2	100.0	74.1	12,765	GAS	775	1,025,000	794.0	3,426	5.53	4.42
BAYSIDE UNIT 5 TOTAL	56	295	0.7	100.0	31.3	14,493	GAS	4,174	1,025,000	4,278.1	18,459	6.26	4.42
BAYSIDE UNIT 6 TOTAL	56	143	0.4	100.0	77.2	12,868	GAS	1,790	1,025,000	1,835.0	7,917	5.54	4.42
BAYSIDE STATION TOTAL	1,854	702,610	52.6	94.0	52.6	7,398	GAS	5,071,028	1,025,000	5,197,803.8	22,497,744	3.20	4.44
SYSTEM	4,932	1,693,474	47.7	84.5	50.7	7,537	-	-	-	12,763,676.5	52,697,554	3.11	-

LEGEND:

B.B. = BIG BEND
CT = COMBUSTION TURBINE

Footnotes:

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ Station Service

CC = COMBINED CYCLE
ST = STEAM TURBINE

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	290	2.0	-	2.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,280	383.5	-	383.5	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,340	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,950	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,310	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,640	30.2	-	30.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,450	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,490	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,810	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	16,390	29.6	-	29.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,360	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,310	32.2	-	32.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL ⁽³⁾	651.9	148,910	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	11,190	4.4	82.2	33.6	14,349	GAS	156,200	1,027,977	160,570.0	776,358	6.94	4.97
19. B.B.#3 (GAS)	345	38,440	15.0	-	-	-	GAS	445,550	1,027,988	458,020.0	2,214,509	5.76	4.97
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	38,440	15.0	83.9	54.6	11,915	-	-	-	458,020.0	2,214,509	5.76	-
22. B.B.#4 (GAS)	155	7,370	6.4	-	-	-	GAS	85,770	1,027,865	88,160.0	426,301	5.78	4.97
23. B.B.#4 (COAL)	422	140,060	44.6	-	-	-	COAL	74,450	22,500,739	1,675,180.0	5,248,735	3.75	70.50
24. BIG BEND #4 TOTAL	422	147,430	47.0	89.7	51.1	11,961	-	-	-	1,763,340.0	5,675,036	3.85	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	24,630	1,028,015	25,320.0	122,418	-	4.97
26. B.B.C.T.#4 TOTAL	56	420	1.0	98.3	46.9	14,833	GAS	6,070	1,026,359	6,230.0	30,170	7.18	4.97
27. B.B.C.T.#5 TOTAL	330	0	0.0	93.4	0.0	0	GAS	0	0	0.0	0	0.00	0.00
28. B.B.C.T.#6 TOTAL	330	0	0.0	97.1	0.0	0	GAS	0	0	0.0	0	0.00	0.00
29. BIG BEND STATION TOTAL	1,823	197,480	14.6	89.5	50.2	12,093	-	-	-	2,388,160.0	8,818,491	4.47	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	29,810	20.9	-	89.2	8,871	GAS	257,240	1,027,989	264,440.0	1,278,555	4.29	4.97
32. POLK #1 TOTAL	220	29,810	18.2	0.0	89.2	8,871	-	-	-	264,440.0	1,278,555	4.29	-
33. POLK #2 ST DUCT FIRING	120	6,950	7.8	-	69.8	8,273	GAS	55,930	1,028,071	57,500.0	277,988	4.00	4.97
34. POLK #2 ST W/O DUCT FIRING	341	585,290	-	-	-	-	-	3,934,435	1,028,005	4,044,620.0	19,555,250	3.34	4.97
35. POLK #2 ST TOTAL	461	592,240	172.7	-	158.2	6,926	GAS	-	-	4,102,120.0	19,833,238	3.35	-
36. POLK #2 CT (GAS)	150	500	0.4	-	83.3	11,300	GAS	5,500	1,027,273	5,650.0	27,337	5.47	4.97
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,609	31.07	139.97
38. POLK #2 TOTAL	150	650	0.6	-	85.6	11,692	-	-	-	7,600.0	73,946	11.38	-
39. POLK #3 CT (GAS)	150	480	0.4	-	80.0	11,542	GAS	5,390	1,027,829	5,540.0	26,790	5.58	4.97
40. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,608	31.07	139.96
41. POLK #3 TOTAL	150	630	0.6	-	83.0	11,889	-	-	-	7,490.0	73,398	11.65	-
42. POLK #4 CT (GAS) TOTAL	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
43. POLK #5 CT (GAS) TOTAL	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
44. POLK #2 CC TOTAL	1,061	593,520	75.2	0.0	157.3	6,937	-	-	-	4,117,210.0	19,980,582	3.37	-
45. POLK STATION TOTAL	1,281	623,330	65.4	0.0	145.4	7,029	-	-	-	4,381,650.0	21,259,137	3.41	-
46. BAYSIDE #1	720	404,140	75.4	97.3	78.2	7,325	GAS	2,879,690	1,028,000	2,960,320.0	14,312,871	3.54	4.97
47. BAYSIDE #2	954	421,280	59.4	97.4	61.0	7,507	GAS	3,076,440	1,027,997	3,162,570.0	15,290,773	3.63	4.97
48. BAYSIDE #3	56	280	0.7	98.6	45.5	15,357	GAS	4,180	1,028,708	4,300.0	20,776	7.42	4.97
49. BAYSIDE #4	56	220	0.5	98.6	39.3	16,318	GAS	3,480	1,031,609	3,590.0	17,297	7.86	4.97
50. BAYSIDE #5	56	730	1.8	98.6	50.1	14,274	GAS	10,140	1,027,613	10,420.0	50,389	6.90	4.97
51. BAYSIDE #6	56	280	0.7	98.6	50.0	14,750	GAS	4,010	1,029,925	4,130.0	19,931	7.12	4.97
52. BAYSIDE STATION TOTAL	1,898	826,930	58.6	97.5	68.3	7,431	GAS	6,977,940	1,028,001	6,146,330.0	29,712,047	3.59	4.97

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	270	1.9	-	1.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,200	376.3	-	376.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	15,770	30.2	-	30.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,350	29.6	-	29.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	16,730	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,170	29.1	-	29.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,040	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,360	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,430	28.4	-	28.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	15,880	28.7	-	28.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	16,780	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	13,820	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL ⁽³⁾	651.9	144,090	29.7	-	29.7	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	10,610	4.2	82.2	32.5	14,530	GAS	149,960	1,028,007	154,160.0	753,445	7.10	5.02
19. B.B.#3 (GAS)	345	41,450	16.1	-	-	-	GAS	480,520	1,027,991	493,970.0	2,414,280	5.82	5.02
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	41,450	16.1	83.9	54.6	11,917	-	-	-	493,970.0	2,414,280	5.82	-
22. B.B.#4 (GAS)	155	8,170	7.1	-	-	-	GAS	92,340	1,028,049	94,930.0	463,944	5.68	5.02
23. B.B.#4 (COAL)	422	155,160	49.4	-	-	-	COAL	80,160	22,500,374	1,803,630.0	5,533,990	3.57	69.04
24. BIG BEND #4 TOTAL	422	163,330	52.0	89.7	56.6	11,624	-	-	-	1,898,560.0	5,997,934	3.67	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	27,140	1,028,003	27,900.0	136,360	-	5.02
26. B.B.C.T.#4 TOTAL	56	360	0.9	98.3	53.6	13,861	GAS	4,850	1,028,866	4,990.0	24,368	6.77	5.02
27. B.B.C.T.#5 TOTAL	330	57,940	23.6	93.4	24.1	9,341	GAS	526,460	1,028,017	541,210.0	2,645,096	4.57	5.02
28. B.B.C.T.#6 TOTAL	330	21,820	8.9	97.1	9.1	9,536	GAS	202,410	1,028,012	208,080.0	1,016,970	4.66	5.02
29. BIG BEND STATION TOTAL	1,823	295,510	21.8	89.5	33.6	11,170	-	-	-	3,300,970.0	12,988,453	4.40	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	19,700	13.8	-	87.0	8,926	GAS	171,080	1,027,882	175,850.0	859,558	4.36	5.02
32. POLK #1 TOTAL	220	19,700	12.0	0.0	87.0	8,926	-	-	-	175,850.0	859,558	4.36	-
33. POLK #2 ST DUCT FIRING	120	4,110	4.6	-	62.3	8,273	GAS	33,070	1,028,122	34,000.0	166,154	4.04	5.02
34. POLK #2 ST W/O DUCT FIRING	341	575,450	-	-	-	-	-	3,867,825	1,028,004	3,976,140.0	19,433,137	3.38	5.02
35. POLK #2 ST TOTAL	461	579,560	169.0	-	160.8	6,919	GAS	-	-	4,010,140.0	19,599,291	3.38	-
36. POLK #2 CT (GAS)	150	1,240	1.1	-	82.7	11,347	GAS	13,690	1,027,757	14,070.0	68,783	5.55	5.02
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,414	30.94	139.38
38. POLK #2 TOTAL	150	1,390	1.2	-	83.8	11,525	-	-	-	16,020.0	115,197	8.29	-
39. POLK #3 CT (GAS)	150	580	0.5	-	96.7	10,914	GAS	6,160	1,027,597	6,330.0	30,950	5.34	5.02
40. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,414	30.94	139.38
41. POLK #3 TOTAL	150	730	0.7	-	96.2	11,342	-	-	-	8,280.0	77,364	10.60	-
42. POLK #4 CT (GAS) TOTAL	150	430	0.4	-	95.6	10,814	GAS	4,520	1,028,761	4,650.0	22,710	5.28	5.02
43. POLK #5 CT (GAS) TOTAL	150	290	0.3	-	96.7	11,241	GAS	3,170	1,028,391	3,260.0	15,927	5.49	5.02
44. POLK #2 CC TOTAL	1,061	582,400	73.8	0.0	158.9	6,941	-	-	-	4,042,350.0	19,830,489	3.40	-
45. POLK STATION TOTAL	1,281	602,100	63.2	0.0	149.7	7,006	-	-	-	4,218,200.0	20,690,047	3.44	-
46. BAYSIDE #1	720	386,100	72.1	97.3	76.7	7,331	GAS	2,753,440	1,027,998	2,830,530.0	13,834,126	3.58	5.02
47. BAYSIDE #2	954	400,690	56.5	97.4	59.2	7,516	GAS	2,929,450	1,027,998	3,011,470.0	14,718,454	3.67	5.02
48. BAYSIDE #3	56	330	0.8	98.6	49.1	14,758	GAS	4,750	1,025,263	4,870.0	23,865	7.23	5.02
49. BAYSIDE #4	56	240	0.6	98.6	47.6	14,750	GAS	3,450	1,026,087	3,540.0	17,334	7.22	5.02
50. BAYSIDE #5	56	690	1.7	98.6	53.6	13,841	GAS	9,290	1,027,987	9,550.0	46,676	6.76	5.02
51. BAYSIDE #6	56	430	1.0	98.6	51.2	14,465	GAS	6,050	1,028,099	6,220.0	30,397	7.07	5.02
52. BAYSIDE STATION TOTAL	1,898	788,480	55.8	97.5	66.7	7,440	GAS	5,706,430	1,027,995	5,866,180.0	28,670,852	3.64	5.02

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	230	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,480	322.2	-	322.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,710	27.2	-	27.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,200	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,400	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,450	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,470	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,760	25.1	-	25.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	9,070	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	13,730	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,420	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	12,030	27.9	-	27.9	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL	⁽³⁾ 651.9	124,210	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	21,020	8.6	82.2	32.2	14,584	GAS	298,200	1,028,035	306,560.0	1,491,000	7.09	5.00
19. B.B.#3 (GAS)	345	27,000	10.9	-	-	-	GAS	313,880	1,027,972	322,660.0	1,569,400	5.81	5.00
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	27,000	10.9	75.5	54.0	11,950	-	-	-	322,660.0	1,569,400	5.81	-
22. B.B.#4 (GAS)	155	7,260	6.5	-	-	-	GAS	84,010	1,027,973	86,360.0	420,050	5.79	5.00
23. B.B.#4 (COAL)	422	137,900	45.4	-	-	-	COAL	72,930	22,499,657	1,640,900.0	4,972,764	3.61	68.19
24. BIG BEND #4 TOTAL	422	145,160	47.8	89.7	52.0	11,899	-	-	-	1,727,260.0	5,392,814	3.72	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	35,900	1,028,134	36,910.0	179,500	-	5.00
26. B.B.C.T.#4 TOTAL	56	70	0.2	98.3	25.0	20,429	GAS	1,390	1,028,777	1,430.0	6,950	9.93	5.00
27. B.B.C.T.#5 TOTAL	330	32,140	13.5	93.4	13.8	9,203	GAS	287,750	1,027,976	295,800.0	1,438,751	4.48	5.00
28. B.B.C.T.#6 TOTAL	330	42,220	17.8	97.1	18.1	9,236	GAS	379,330	1,027,970	389,940.0	1,896,651	4.49	5.00
29. BIG BEND STATION TOTAL	1,823	267,610	20.4	87.9	31.1	11,373	-	-	-	3,043,650.0	11,975,067	4.47	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	22,200	16.1	-	88.3	8,910	GAS	192,410	1,028,013	197,800.0	962,050	4.33	5.00
32. POLK #1 TOTAL	220	22,200	14.0	0.0	88.3	8,910	-	-	-	197,800.0	962,050	4.33	-
33. POLK #2 ST DUCT FIRING	120	3,660	4.2	-	58.7	8,265	GAS	29,430	1,027,863	30,250.0	147,150	4.02	5.00
34. POLK #2 ST W/O DUCT FIRING	341	544,460	-	-	-	-	-	3,661,355	1,028,005	3,763,890.0	18,306,782	3.36	5.00
35. POLK #2 ST TOTAL	461	548,120	165.1	-	156.2	6,922	GAS	-	-	3,794,140.0	18,453,932	3.37	-
36. POLK #2 CT (GAS)	150	1,380	1.3	-	92.0	10,899	GAS	14,630	1,028,025	15,040.0	73,151	5.30	5.00
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,223	30.82	138.81
38. POLK #2 TOTAL	⁽⁴⁾ 150	1,530	1.4	-	92.2	11,105	-	-	-	16,990.0	119,374	7.80	-
39. POLK #3 CT (GAS)	150	1,390	1.3	-	92.7	10,942	GAS	14,800	1,027,703	15,210.0	74,000	5.32	5.00
40. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,222	30.81	138.80
41. POLK #3 TOTAL	⁽⁴⁾ 150	1,540	1.4	-	92.8	11,143	-	-	-	17,160.0	120,222	7.81	-
42. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	880	0.8	-	97.8	10,693	GAS	9,150	1,028,415	9,410.0	45,750	5.20	5.00
43. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	1,010	0.9	-	96.2	10,871	GAS	10,680	1,028,090	10,980.0	53,400	5.29	5.00
44. POLK #2 CC TOTAL	1,061	553,080	72.4	0.0	153.5	6,959	-	-	-	3,848,680.0	18,792,678	3.40	-
45. POLK STATION TOTAL	1,281	575,280	62.4	0.0	144.3	7,034	-	-	-	4,046,480.0	19,754,728	3.43	-
46. BAYSIDE #1	720	374,200	72.2	97.3	74.2	7,347	GAS	2,674,490	1,027,998	2,749,370.0	13,372,455	3.57	5.00
47. BAYSIDE #2	954	364,550	53.1	97.4	54.7	7,572	GAS	2,685,260	1,028,005	2,760,460.0	13,426,306	3.68	5.00
48. BAYSIDE #3	56	510	1.3	98.6	56.9	13,882	GAS	6,890	1,027,576	7,080.0	34,450	6.75	5.00
49. BAYSIDE #4	56	240	0.6	98.6	47.6	14,208	GAS	3,320	1,027,108	3,410.0	16,600	6.92	5.00
50. BAYSIDE #5	56	830	2.1	98.6	57.0	13,422	GAS	10,850	1,026,728	11,140.0	54,250	6.54	5.00
51. BAYSIDE #6	56	710	1.8	98.6	57.6	13,563	GAS	9,380	1,026,652	9,630.0	46,900	6.61	5.00
52. BAYSIDE STATION TOTAL	1,898	741,040	54.2	97.5	63.1	7,477	GAS	5,390,190	1,027,995	5,541,090.0	26,950,961	3.64	5.00

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	220	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,600	322.6	-	322.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,550	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,050	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,040	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,300	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,340	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	7,140	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,970	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	14,260	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,090	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,890	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL	⁽³⁾ 651.9	123,740	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	12,190	4.8	82.2	32.6	14,510	GAS	172,070	1,027,954	176,880.0	851,827	6.99	4.95
19. B.B.#3 (GAS)	345	27,200	10.6	-	-	-	GAS	315,660	1,028,005	324,500.0	1,562,666	5.75	4.95
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	27,200	10.6	64.9	54.4	11,930	-	-	-	324,500.0	1,562,666	5.75	-
22. B.B.#4 (GAS)	155	1,500	1.3	-	-	-	GAS	18,010	1,028,318	18,520.0	89,158	5.94	4.95
23. B.B.#4 (COAL)	422	28,490	9.1	-	-	-	COAL	15,640	22,496,803	351,850.0	1,109,083	3.89	70.91
24. BIG BEND #4 TOTAL	422	29,990	9.6	20.3	45.8	12,350	-	-	-	370,370.0	1,198,241	4.00	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	27,140	1,028,003	27,900.0	134,356	-	4.95
26. B.B.C.T.#4 TOTAL	56	220	0.5	98.3	32.7	16,727	GAS	3,570	1,030,812	3,680.0	17,673	8.03	4.95
27. B.B.C.T.#5 TOTAL	330	112,500	45.8	93.4	46.7	9,201	GAS	1,006,930	1,027,996	1,035,120.0	4,984,777	4.43	4.95
28. B.B.C.T.#6 TOTAL	330	78,720	32.1	97.1	32.7	9,201	GAS	704,580	1,027,988	724,300.0	3,488,002	4.43	4.95
29. BIG BEND STATION TOTAL	1,823	260,820	19.2	69.8	41.1	10,102	-	-	-	2,634,850.0	12,237,542	4.69	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	26,840	18.8	-	86.3	8,918	GAS	232,830	1,028,003	239,350.0	1,152,618	4.29	4.95
32. POLK #1 TOTAL	220	26,840	16.4	0.0	86.3	8,918	-	-	-	239,350.0	1,152,618	4.29	-
33. POLK #2 ST DUCT FIRING	120	2,530	2.8	-	49.0	8,277	GAS	20,370	1,027,982	20,940.0	100,841	3.99	4.95
34. POLK #2 ST W/O DUCT FIRING	341	505,400	-	-	-	-	-	3,403,045	1,028,003	3,498,340.0	16,846,672	3.33	4.95
35. POLK #2 ST TOTAL	461	507,930	148.1	-	142.5	6,929	GAS	-	-	3,519,280.0	16,947,513	3.34	-
36. POLK #2 CT (GAS)	150	1,440	1.3	-	80.0	11,451	GAS	16,050	1,027,414	16,490.0	79,455	5.52	4.95
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,034	30.69	138.24
38. POLK #2 TOTAL	⁽⁴⁾ 150	1,590	1.4	-	81.2	11,597	-	-	-	18,440.0	125,489	7.89	-
39. POLK #3 CT (GAS)	150	1,440	1.3	-	80.0	11,451	GAS	16,050	1,027,414	16,490.0	79,455	5.52	4.95
40. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	46,035	30.69	138.24
41. POLK #3 TOTAL	⁽⁴⁾ 150	1,590	1.4	-	81.2	11,597	-	-	-	18,440.0	125,490	7.89	-
42. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
43. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	910	0.8	-	86.7	11,209	GAS	9,930	1,027,190	10,200.0	49,158	5.40	4.95
44. POLK #2 CC TOTAL	1,061	512,020	64.9	0.0	140.1	6,965	-	-	-	3,566,360.0	17,247,650	3.37	-
45. POLK STATION TOTAL	1,281	538,860	56.5	0.0	131.1	7,063	-	-	-	3,805,710.0	18,400,268	3.41	-
46. BAYSIDE #1	720	300,570	56.1	84.7	66.6	7,401	GAS	2,164,030	1,027,999	2,224,620.0	10,712,966	3.56	4.95
47. BAYSIDE #2	954	323,770	45.6	91.1	46.9	7,685	GAS	2,420,380	1,028,000	2,488,150.0	11,982,018	3.70	4.95
48. BAYSIDE #3	56	110	0.3	98.6	39.3	16,364	GAS	1,750	1,028,571	1,800.0	8,663	7.88	4.95
49. BAYSIDE #4	56	90	0.2	98.6	32.1	18,111	GAS	1,580	1,031,646	1,630.0	7,822	8.69	4.95
50. BAYSIDE #5	56	280	0.7	98.6	35.7	17,357	GAS	4,730	1,027,484	4,860.0	23,416	8.36	4.95
51. BAYSIDE #6	56	190	0.5	98.6	28.3	19,579	GAS	3,630	1,024,793	3,720.0	17,970	9.46	4.95
52. BAYSIDE STATION TOTAL	1,898	625,010	44.3	89.6	54.7	7,560	GAS	4,596,100	1,027,998	4,724,780.0	22,752,855	3.64	4.95

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	180	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,970	274.6	-	274.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	10,130	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,500	19.6	-	19.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,030	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,420	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,720	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,040	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,700	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	11,780	22.0	-	22.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,070	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,900	20.6	-	20.6	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
16. SOLAR TOTAL	⁽³⁾ 651.9	97,710	20.8	-	20.8	-	SOLAR	-	-	-	-	-	-
17. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
18. BIG BEND #2 TOTAL	340	21,640	8.8	82.2	40.5	13,391	GAS	281,890	1,027,990	289,780.0	1,378,566	6.37	4.89
19. B.B.#3 (GAS)	345	53,180	21.4	-	-	-	GAS	617,500	1,028,000	634,790.0	3,019,847	5.68	4.89
20. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #3 TOTAL	345	53,180	21.4	83.9	54.3	11,937	-	-	-	634,790.0	3,019,847	5.68	-
22. B.B.#4 (GAS)	155	1,360	1.2	-	-	-	GAS	16,070	1,028,002	16,520.0	78,589	5.78	4.89
23. B.B.#4 (COAL)	422	25,870	8.5	-	-	-	COAL	13,950	22,496,774	313,830.0	952,197	3.68	68.26
24. BIG BEND #4 TOTAL	422	27,230	8.9	17.9	48.5	12,132	-	-	-	330,350.0	1,030,786	3.79	-
25. B.B. IGNITION	-	-	-	-	-	-	GAS	44,660	1,027,989	45,910.0	218,407	-	4.89
26. B.B.C.T.#4 TOTAL	56	2,090	5.2	98.3	67.9	12,660	GAS	25,740	1,027,972	26,460.0	125,880	6.02	4.89
27. B.B.C.T.#5 TOTAL	330	78,720	33.1	87.2	33.8	9,201	GAS	704,580	1,028,002	724,310.0	3,445,706	4.38	4.89
28. B.B.C.T.#6 TOTAL	330	87,460	36.8	51.8	37.5	9,202	GAS	782,860	1,028,000	804,780.0	3,826,529	4.38	4.89
29. BIG BEND STATION TOTAL	1,823	270,320	20.6	63.5	40.0	10,397	-	-	-	2,810,470.0	13,047,721	4.83	-
30. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
31. POLK #1 CT (GAS)	192	83,360	60.2	-	89.9	8,776	GAS	711,640	1,028,020	731,580.0	3,480,232	4.17	4.89
32. POLK #1 TOTAL	220	83,360	52.6	0.0	89.9	8,776	-	-	-	731,580.0	3,480,232	4.17	-
33. POLK #2 ST DUCT FIRING	120	6,840	7.9	-	57.0	8,281	GAS	55,090	1,028,136	56,640.0	269,414	3.94	4.89
34. POLK #2 ST W/O DUCT FIRING	341	254,910	-	-	-	-	-	1,715,318	1,028,002	1,763,350.0	8,388,659	3.29	4.89
35. POLK #2 ST TOTAL	461	261,750	78.7	-	119.5	6,953	GAS	-	-	1,819,990.0	8,658,073	3.31	-
36. POLK #2 CT (GAS)	150	17,610	16.3	-	76.2	11,606	GAS	198,820	1,028,015	204,390.0	972,318	5.52	4.89
37. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	45,941	30.63	137.96
38. POLK #2 TOTAL	⁽⁴⁾ 150	17,760	16.4	-	76.4	11,618	-	-	-	206,340.0	1,018,259	5.73	-
39. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. POLK #3 CT (OIL)	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
41. POLK #3 TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	-	-	-	0.0	0	0.00	-
42. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	10,680	9.9	-	81.8	11,378	GAS	118,210	1,028,001	121,520.0	578,099	5.41	4.89
43. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	8,040	7.4	-	85.1	11,249	GAS	87,980	1,027,961	90,440.0	430,261	5.35	4.89
44. POLK #2 CC TOTAL	1,061	298,230	39.0	0.0	104.0	7,505	-	-	-	2,238,290.0	10,684,692	3.58	-
45. POLK STATION TOTAL	1,281	381,590	41.3	0.0	98.6	7,783	-	-	-	2,969,870.0	14,164,924	3.71	-
46. BAYSIDE #1	720	243,960	47.0	64.9	73.5	7,355	GAS	1,745,420	1,027,993	1,794,280.0	8,535,871	3.50	4.89
47. BAYSIDE #2	954	378,000	55.0	58.5	60.6	7,511	GAS	2,761,780	1,028,000	2,839,110.0	13,506,318	3.57	4.89
48. BAYSIDE #3	56	2,610	6.5	98.6	80.4	12,115	GAS	30,780	1,027,290	31,620.0	150,528	5.77	4.89
49. BAYSIDE #4	56	2,090	5.2	98.6	77.8	12,316	GAS	25,040	1,027,955	25,740.0	122,457	5.86	4.89
50. BAYSIDE #5	56	3,350	8.3	98.6	75.7	12,313	GAS	40,120	1,028,166	41,250.0	196,204	5.86	4.89
51. BAYSIDE #6	56	2,670	6.6	98.6	74.5	12,375	GAS	32,140	1,028,002	33,040.0	157,179	5.89	4.89
52. BAYSIDE STATION TOTAL	1,898	632,680	46.2	65.6	65.2	7,532	GAS	4,635,280	1,027,994	4,765,040.0	22,668,557	3.58	4.89

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	160	1.1	-	1.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,700	241.9	-	241.9	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	8,500	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	8,500	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	10,420	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	7,070	15.6	-	15.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	6,480	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,050	18.1	-	18.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	5,620	15.3	-	15.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.4	10,490	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	10,460	18.9	-	18.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	7,470	16.8	-	16.8	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,020	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	6,350	11.5	-	11.5	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	9,010	23.2	-	23.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	9,010	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽²⁾ 877.7	110,870	17.0	-	17.0	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	355	19,280	7.3	-	-	-	GAS	220,730	1,027,998	226,910.0	1,119,759	5.81	5.07
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	355	19,280	7.3	83.9	53.8	11,769	-	-	-	226,910.0	1,119,759	5.81	-
24. B.B.#4 (GAS)	160	8,350	7.0	-	-	-	GAS	93,250	1,027,989	95,860.0	473,056	5.67	5.07
25. B.B.#4 (COAL)	432	158,610	43.3	-	-	-	COAL	80,950	22,500,062	1,821,380.0	5,503,061	3.47	67.98
26. BIG BEND #4 TOTAL	432	166,960	51.9	89.7	56.5	11,483	-	-	-	1,917,240.0	5,976,117	3.58	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	10,860	1,027,624	11,160.0	55,093	-	5.07
28. B.B.C.T.#4 TOTAL	61	380	0.8	98.3	56.6	13,184	GAS	4,880	1,026,639	5,010.0	24,756	6.51	5.07
29. B.B.C.T.#5 TOTAL	350	38,200	14.7	57.3	66.1	9,526	GAS	353,980	1,027,968	363,880.0	1,795,734	4.70	5.07
30. B.B.C.T.#6 TOTAL	350	13,880	5.3	97.1	52.2	9,656	GAS	130,380	1,027,995	134,030.0	661,415	4.77	5.07
31. BIG BEND STATION TOTAL	1,898	238,700	16.9	67.7	57.3	11,090	-	-	-	2,647,070.0	9,632,874	4.04	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	192	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. POLK #1 TOTAL	220	0	0.0	0.0	0.0	0	-	-	-	0.0	0	0.00	-
35. POLK #2 ST DUCT FIRING	120	8,580	9.6	-	68.1	8,175	GAS	68,230	1,027,994	70,140.0	346,130	4.03	5.07
36. POLK #2 ST W/O DUCT FIRING	360	614,500	-	-	-	-	-	4,141,185	1,028,003	4,257,150.0	21,008,159	3.42	5.07
37. POLK #2 ST TOTAL	480	623,080	174.5	-	155.1	6,945	GAS	-	-	4,327,290.0	21,354,289	3.43	-
38. POLK #2 CT (GAS)	180	1,380	1.0	-	76.7	11,000	GAS	14,770	1,027,759	15,180.0	74,927	5.43	5.07
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,757	30.50	137.41
40. POLK #2 TOTAL	⁽⁴⁾ 180	1,530	1.1	-	77.0	11,196	-	-	-	17,130.0	120,684	7.89	-
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,756	30.50	137.41
43. POLK #3 TOTAL	⁽⁴⁾ 180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,756	30.50	-
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 180	1,240	0.9	-	76.5	10,968	GAS	13,230	1,027,967	13,600.0	67,116	5.41	5.07
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,200	626,000	70.1	98.0	153.2	6,965	-	-	-	4,359,970.0	21,587,845	3.45	-
47. POLK STATION TOTAL	1,420	626,000	59.3	82.8	153.2	6,965	-	-	-	4,359,970.0	21,587,845	3.45	-
48. BAYSIDE #1	792	385,590	65.4	97.3	70.6	7,250	GAS	2,719,560	1,028,001	2,795,710.0	13,796,280	3.58	5.07
49. BAYSIDE #2	1,047	155,660	20.0	97.4	35.3	7,797	GAS	1,180,610	1,028,011	1,213,680.0	5,989,214	3.85	5.07
50. BAYSIDE #3	61	530	1.2	98.6	66.8	12,491	GAS	6,440	1,027,950	6,620.0	32,670	6.16	5.07
51. BAYSIDE #4	61	470	1.0	98.6	70.0	12,383	GAS	5,060	1,028,269	5,820.0	28,713	6.11	5.07
52. BAYSIDE #5	61	1,020	2.2	98.6	72.7	12,059	GAS	11,960	1,028,428	12,300.0	60,673	5.95	5.07
53. BAYSIDE #6	61	920	2.0	98.6	71.8	12,196	GAS	10,910	1,028,414	11,220.0	55,346	6.02	5.07
54. BAYSIDE STATION TOTAL	2,083	544,190	35.1	97.5	54.9	7,434	GAS	3,935,140	1,028,007	4,045,350.0	19,962,896	3.67	5.07
55. SYSTEM TOTAL	6,279	1,519,760	32.5	71.6	90.1	7,272	-	-	-	11,052,390.0	51,183,615	3.37	-

LEGEND:

⁽¹⁾ As burned fuel cost system total includes ignition⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E5

	ACTUAL					
	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT (\$)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT (\$)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT (\$)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	0	0	0	5,311	0	0
16. UNIT COST (\$/BBL)	0.00	0.00	0.00	86.72	0.00	0.00
17. AMOUNT (\$)	0	0	0	460,555	0	0
18. BURNED:						
19. UNITS (BBL)	115	588	121	408	184	365
20. UNIT COST (\$/BBL)	148.10	148.38	148.17	140.61	140.45	140.70
21. AMOUNT (\$)	17,031	87,245	17,929	57,370	25,842	51,354
22. ENDING INVENTORY:						
23. UNITS (BBL)	38,114	37,526	37,406	42,309	42,125	41,760
24. UNIT COST (\$/BBL)	148.42	148.42	148.41	140.75	140.75	140.75
25. AMOUNT (\$)	5,656,781	5,569,536	5,551,607	5,954,792	5,928,950	5,877,596
26. DAYS SUPPLY: NORMAL	632	623	621	702	699	693
27. DAYS SUPPLY: EMERGENCY	5	5	5	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	36,182	20,086	91,883	51,062	96,156	29,578
30. UNIT COST (\$/TON)	68.37	49.48	76.55	72.96	50.60	63.90
31. AMOUNT (\$)	2,473,940	993,842	7,033,540	3,725,659	4,865,552	1,890,054
32. BURNED:						
33. UNITS (TONS)	36,182	90,829	58,946	32,825	49,854	86,003
34. UNIT COST (\$/TON)	69.75	82.55	81.43	85.41	77.25	70.52
35. AMOUNT (\$)	2,523,735	7,498,306	4,799,736	2,803,672	3,851,041	6,065,132
36. ENDING INVENTORY:						
37. UNITS (TONS)	243,210	172,467	205,404	223,641	269,943	213,518
38. UNIT COST (\$/TON)	73.88	72.05	73.38	73.28	65.89	65.58
39. AMOUNT (\$)	17,967,736	12,426,070	15,071,760	16,388,812	17,787,482	14,001,965
40. DAYS SUPPLY:	163	129	153	111	118	91
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	8,957,328	7,770,059	9,957,967	10,158,688	11,564,720	10,457,690
43. UNIT COST (\$/MCF)	2.12	3.81	5.18	3.44	4.04	4.44
44. AMOUNT (\$)	19,015,576	29,595,798	51,567,813	34,948,873	46,685,843	46,402,414
45. BURNED:						
46. UNITS (MCF)	9,027,318	8,122,935	9,620,165	10,225,351	11,410,833	10,516,609
47. UNIT COST (\$/MCF)	3.60	3.88	3.75	3.44	4.05	4.43
48. AMOUNT (\$)	32,506,200	31,540,062	36,066,578	35,178,663	46,203,567	46,581,068
49. ENDING INVENTORY:						
50. UNITS (MCF)	396,695	43,819	381,621	314,958	468,845	409,926
51. UNIT COST (\$/MCF)	2.64	2.89	2.98	2.88	2.97	3.13
52. AMOUNT (\$)	1,046,930	126,824	1,138,159	908,369	1,390,645	1,282,888
53. DAYS SUPPLY:	1	0	1	1	1	1
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT (\$)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT (\$)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT (\$)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT (\$)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING

(1) LIGHT OIL-IGNITION, OTHER USAGE, AND ANALYSIS

(2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENTS

(3) GAS-IGNITION AND ADDITIVES

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

SCHEDULE E5

	Jul-21	Aug-21	Estimated Sep-21	Oct-21	Nov-21	Dec-21	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	0	0	0	0	0	0	0
3. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT (\$)	0	0	0	0	0	0	0
5. BURNED:							
6. UNITS (BBL)	0	0	0	0	0	0	0
7. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT (\$)	0	0	0	0	0	0	0
9. ENDING INVENTORY:							
10. UNITS (BBL)	0	0	0	0	0	0	0
11. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT (\$)	0	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	665	665	665	665	333	665	8,969
16. UNIT COST (\$/BBL)	102.19	102.80	102.91	102.93	102.72	102.78	93.25
17. AMOUNT (\$)	67,954	68,362	68,438	68,450	34,207	68,349	836,315
18. BURNED:							
19. UNITS (BBL)	666	666	666	666	333	666	5,444
20. UNIT COST (\$/BBL)	139.97	139.38	138.81	138.24	137.96	137.41	140.48
21. AMOUNT (\$)	93,217	92,828	92,445	92,069	45,941	91,513	764,784
22. ENDING INVENTORY:							
23. UNITS (BBL)	41,760	41,760	41,760	41,760	41,760	41,760	41,760
24. UNIT COST (\$/BBL)	140.14	139.56	138.98	138.42	138.13	137.58	137.58
25. AMOUNT (\$)	5,852,333	5,827,867	5,803,859	5,780,241	5,768,507	5,745,343	5,745,343
26. DAYS SUPPLY: NORMAL	1,993	1,993	1,993	1,993	1,993	1,910	-
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
COAL							
28. PURCHASES:							
29. UNITS (TONS)	95,000	70,000	55,000	52,500	52,500	40,000	689,947
30. UNIT COST (\$/TON)	60.90	57.80	57.80	60.67	60.67	57.80	61.85
31. AMOUNT (\$)	5,785,728	4,046,151	3,179,119	3,184,964	3,184,964	2,312,087	42,675,600
32. BURNED:							
33. UNITS (TONS)	74,450	80,160	72,930	15,640	13,950	80,950	692,719
34. UNIT COST (\$/TON)	70.50	69.04	68.19	70.91	68.26	67.98	73.42
35. AMOUNT (\$)	5,248,735	5,533,990	4,972,764	1,109,083	952,197	5,503,061	50,861,452
36. ENDING INVENTORY:							
37. UNITS (TONS)	234,068	223,908	205,978	242,838	281,388	240,438	240,438
38. UNIT COST (\$/TON)	64.07	62.53	61.44	61.23	61.08	60.28	60.28
39. AMOUNT (\$)	14,996,551	14,001,400	12,656,006	14,868,015	17,186,523	14,493,093	14,493,093
40. DAYS SUPPLY:	95	122	183	202	155	100	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	10,933,834	11,289,625	10,723,105	10,542,335	9,995,638	8,986,635	121,337,624
43. UNIT COST (\$/MCF)	4.99	5.03	5.00	4.95	4.89	5.08	4.45
44. AMOUNT (\$)	54,611,635	56,734,454	53,604,987	52,187,993	48,899,784	45,624,400	539,879,570
45. BURNED:							
46. UNITS (MCF)	10,954,655	11,289,625	10,723,105	10,542,335	9,995,638	8,986,635	121,415,204
47. UNIT COST (\$/MCF)	4.97	5.02	5.00	4.95	4.89	5.07	4.44
48. AMOUNT (\$)	54,447,723	56,722,534	53,615,547	52,189,513	48,883,064	45,589,041	539,523,560
49. ENDING INVENTORY:							
50. UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105	389,105
51. UNIT COST (\$/MCF)	3.72	3.75	3.72	3.72	3.76	3.85	3.85
52. AMOUNT (\$)	1,446,800	1,458,720	1,448,161	1,446,640	1,463,360	1,498,720	1,498,720
53. DAYS SUPPLY:	1	1	1	1	1	1	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT (\$)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT (\$)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT (\$)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT (\$)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING

(1) LIGHT OIL-IGNITION AND ANALYSIS (2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENTS (3) GAS-IGNITION

TAMPA ELECTRIC COMPANY
POWER SOLD
ACTUAL FOR THE PERIOD: JANUARY 2021 THROUGH JUNE 2021

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH		CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES
				WHEELED	FROM OWN	(A)	(B)			
				OTHER SYSTEMS	GENERATION	FUEL COST	TOTAL COST			
ACTUAL										
Jan-21	SEMINOLE	JURISD.	SCH. - D	3,130.0	0.0	3,130.0	1.925	2.118	60,254.47	4,066.61
	VARIOUS	JURISD.	SCH. - MA	500.0	0.0	500.0	6.817	3.562	34,082.75	(19,569.73)
	TOTAL			3,630.0	0.0	3,630.0	2.599	2.316	94,337.22	(15,503.12)
ACTUAL										
Feb-21	SEMINOLE	JURISD.	SCH. - D	3,307.0	0.0	3,307.0	3.635	3.998	120,198.44	9,721.57
	VARIOUS	JURISD.	SCH. - MA	1,413.0	0.0	1,413.0	3.639	5.260	51,415.96	22,413.29
	TOTAL			4,720.0	0.0	4,720.0	3.636	4.376	171,614.40	32,134.86
ACTUAL										
Mar-21	SEMINOLE	JURISD.	SCH. - D	3,060.0	0.0	3,060.0	1.867	2.054	57,128.87	3,704.76
	VARIOUS	JURISD.	SCH. - MA	40.0	0.0	40.0	1.707	2.694	682.80	320.31
	TOTAL			3,100.0	0.0	3,100.0	1.865	2.062	57,811.67	4,025.07
ACTUAL										
Apr-21	SEMINOLE	JURISD.	SCH. - D	2,431.0	0.0	2,431.0	1.776	1.953	43,172.02	3,339.30
	VARIOUS	JURISD.	SCH. - MA	2,625.0	0.0	2,625.0	2.063	3.223	54,157.50	25,667.06
	TOTAL			5,056.0	0.0	5,056.0	1.925	2.613	97,329.52	29,006.36
ACTUAL										
May-21	SEMINOLE	JURISD.	SCH. - D	1,623.0	0.0	1,623.0	1.903	2.094	30,891.60	2,293.51
	VARIOUS	JURISD.	SCH. - MA	5,300.0	0.0	5,300.0	2.244	3.343	118,945.00	47,628.07
	TOTAL			6,923.0	0.0	6,923.0	2.164	3.050	149,836.60	49,921.58
ACTUAL										
Jun-21	SEMINOLE	JURISD.	SCH. - D	1,621.0	0.0	1,621.0	1.998	2.198	32,389.91	1,782.60
	VARIOUS	JURISD.	SCH. - MA	2,090.0	0.0	2,090.0	2.315	3.754	48,384.15	26,082.94
	TOTAL			3,711.0	0.0	3,711.0	2.177	3.074	80,774.06	27,865.54

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2021 THROUGH DECEMBER 2021

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		
		TYPE & SCHEDULE	TOTAL MWH SOLD	MWH		CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES	
				WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST				
MONTH	SOLD TO										
ESTIMATED											
Jul-21	SEMINOLE	JURISD.	SCH. - D	2,880.0	0.0	2,880.0	2.937	3.144	84,590.00	90,552.00	5,962.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,880.0	0.0	2,880.0	2.937	3.144	84,590.00	90,552.00	5,962.00
ESTIMATED											
Aug-21	SEMINOLE	JURISD.	SCH. - D	2,980.0	0.0	2,980.0	2.930	3.136	87,310.00	93,463.00	6,153.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,980.0	0.0	2,980.0	2.930	3.136	87,310.00	93,463.00	6,153.00
ESTIMATED											
Sep-21	SEMINOLE	JURISD.	SCH. - D	2,970.0	0.0	2,970.0	2.862	3.064	85,010.00	91,001.00	5,991.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,970.0	0.0	2,970.0	2.862	3.064	85,010.00	91,001.00	5,991.00
ESTIMATED											
Oct-21	SEMINOLE	JURISD.	SCH. - D	2,880.0	0.0	2,880.0	2.802	2.999	80,690.00	86,377.00	5,687.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,880.0	0.0	2,880.0	2.802	2.999	80,690.00	86,377.00	5,687.00
ESTIMATED											
Nov-21	SEMINOLE	JURISD.	SCH. - D	2,920.0	0.0	2,920.0	3.113	3.332	90,900.00	97,306.00	6,406.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,920.0	0.0	2,920.0	3.113	3.332	90,900.00	97,306.00	6,406.00
ESTIMATED											
Dec-21	SEMINOLE	JURISD.	SCH. - D	2,940.0	0.0	2,940.0	3.047	3.262	89,580.00	95,893.00	6,313.00
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,940.0	0.0	2,940.0	3.047	3.262	89,580.00	95,893.00	6,313.00
TOTAL											
Jan-21	SEMINOLE	JURISD.	SCH. - D	32,742.0	0.0	32,742.0	2.633	2.850	862,115.31	933,030.84	61,420.35
THRU	VARIOUS	JURISD.	SCH. - MA	11,968.0	0.0	11,968.0	2.571	3.622	307,668.16	433,436.37	102,541.94
Dec-21	TOTAL			44,710.0	0.0	44,710.0	2.616	3.056	1,169,783.47	1,366,467.21	163,962.29

TAMPA ELECTRIC COMPANY PURCHASED POWER (EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES) ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021								SCHEDULE E7	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT
							(A) FUEL COST	(B) TOTAL COST	
ACTUAL									
Jan-21	VARIOUS	SCH. - J	152,282.0	0.0	0.0	152,282.0	3.346	3.346	5,095,948.34
	VARIOUS	OATT	1,350.0	0.0	0.0	1,350.0	2.794	2.794	37,714.91
	TOTAL		153,632.0	0.0	0.0	153,632.0	3.342	3.342	5,133,663.25
ACTUAL									
Feb-21	VARIOUS	SCH. - J	14,230.0	0.0	0.0	14,230.0	8.326	8.326	1,184,807.77
	VARIOUS	OATT	183.0	0.0	0.0	183.0	6.823	6.823	12,485.55
	TOTAL		14,413.0	0.0	0.0	14,413.0	8.307	8.307	1,197,293.32
ACTUAL									
Mar-21	VARIOUS	SCH. - J	10,482.0	0.0	0.0	10,482.0	6.764	6.764	708,966.14
	VARIOUS	OATT	105.0	0.0	0.0	105.0	7.336	7.336	7,702.64
	TOTAL		10,587.0	0.0	0.0	10,587.0	6.769	6.769	716,668.78
ACTUAL									
Apr-21	VARIOUS	SCH. - J	5,012.0	0.0	0.0	5,012.0	5.302	5.302	265,748.50
	VARIOUS	OATT	1,065.0	0.0	0.0	1,065.0	3.852	3.852	41,020.42
	TOTAL		6,077.0	0.0	0.0	6,077.0	5.048	5.048	306,768.92
ACTUAL									
May-21	VARIOUS	SCH. - J	16,005.0	0.0	0.0	16,005.0	8.360	8.360	1,338,078.77
	VARIOUS	OATT	1,266.0	0.0	0.0	1,266.0	4.018	4.018	50,872.12
	TOTAL		17,271.0	0.0	0.0	17,271.0	8.042	8.042	1,388,950.89
ACTUAL									
Jun-21	VARIOUS	SCH. - J	20,160.0	0.0	0.0	20,160.0	4.052	4.052	816,922.17
	VARIOUS	OATT	1,196.0	0.0	0.0	1,196.0	3.778	3.778	45,183.47
	TOTAL		21,356.0	0.0	0.0	21,356.0	4.037	4.037	862,105.64
ESTIMATED									
Jul-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Aug-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Sep-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Oct-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Nov-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ESTIMATED									
Dec-21	VARIOUS	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL									
Jan-21	VARIOUS	SCH. - J	218,171.0	0.0	0.0	218,171.0	4.313	4.313	9,410,471.69
THRU	VARIOUS	OATT	5,165.0	0.0	0.0	5,165.0	3.775	3.775	194,979.11
Dec-21	TOTAL		223,336.0	0.0	0.0	223,336.0	4.301	4.301	9,605,450.80

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL \$ FOR FUEL ADJUSTMENT
ACTUAL Jan-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	4.0 3,505.0	0.0 0.0	0.0 0.0	4.0 3,505.0	2.208 1.861	2.208 1.861	88.26 65,231.34
	TOTAL		3,509.0	0.0	0.0	3,509.0	1.861	1.861	65,319.60
ACTUAL Feb-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	2,415.0 8,488.0	0.0 0.0	0.0 0.0	2,415.0 8,488.0	1.813 3.573	1.813 3.573	43,774.05 303,300.02
	TOTAL		10,903.0	0.0	0.0	10,903.0	3.183	3.183	347,074.07
ACTUAL Mar-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	131.2 10,325.0	0.0 0.0	0.0 0.0	131.2 10,325.0	1.811 2.052	1.811 2.052	2,375.51 211,878.38
	TOTAL		10,456.2	0.0	0.0	10,456.2	2.049	2.049	214,253.89
ACTUAL Apr-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	24.1 2,978.0	0.0 0.0	0.0 0.0	24.1 2,978.0	1.814 1.696	1.814 1.696	437.85 50,503.23
	TOTAL		3,002.1	0.0	0.0	3,002.1	1.697	1.697	50,941.08
ACTUAL May-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	16.9 9,085.0	0.0 0.0	0.0 0.0	16.9 9,085.0	1.814 1.999	1.814 1.999	306.62 181,581.07
	TOTAL		9,101.9	0.0	0.0	9,101.9	1.998	1.998	181,887.69
ACTUAL Jun-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	33.5 10,697.0	0.0 0.0	0.0 0.0	33.5 10,697.0	1.814 2.140	1.814 2.140	606.82 228,944.75
	TOTAL		10,730.5	0.0	0.0	10,730.5	2.139	2.139	229,551.57
ESTIMATED Jul-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,060.0	0.0 0.0	0.0 0.0	0.0 5,060.0	0.000 3.622	0.000 3.622	0.00 183,290.00
	TOTAL		5,060.0	0.0	0.0	5,060.0	3.622	3.622	183,290.00
ESTIMATED Aug-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,230.0	0.0 0.0	0.0 0.0	0.0 5,230.0	0.000 3.604	0.000 3.604	0.00 188,490.00
	TOTAL		5,230.0	0.0	0.0	5,230.0	3.604	3.604	188,490.00
ESTIMATED Sep-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,160.0	0.0 0.0	0.0 0.0	0.0 5,160.0	0.000 3.132	0.000 3.132	0.00 161,600.00
	TOTAL		5,160.0	0.0	0.0	5,160.0	3.132	3.132	161,600.00
ESTIMATED Oct-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,120.0	0.0 0.0	0.0 0.0	0.0 5,120.0	0.000 2.980	0.000 2.980	0.00 152,560.00
	TOTAL		5,120.0	0.0	0.0	5,120.0	2.980	2.980	152,560.00
ESTIMATED Nov-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,160.0	0.0 0.0	0.0 0.0	0.0 5,160.0	0.000 2.909	0.000 2.909	0.00 150,110.00
	TOTAL		5,160.0	0.0	0.0	5,160.0	2.909	2.909	150,110.00
ESTIMATED Dec-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	0.0 5,160.0	0.0 0.0	0.0 0.0	0.0 5,160.0	0.000 2.612	0.000 2.612	0.00 134,790.00
	TOTAL		5,160.0	0.0	0.0	5,160.0	2.612	2.612	134,790.00
TOTAL Jan-21 THRU Dec-21	VARIOUS	CO-GEN. NET METERING AS AVAIL.	2,624.7 75,968.0	0.0 0.0	0.0 0.0	2,624.7 75,968.0	1.813 2.649	1.813 2.649	47,589.11 2,012,278.79
	TOTAL		78,592.7	0.0	0.0	78,592.7	2.621	2.621	2,059,867.90

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	TRANSACTION COST cents/KWH	TOTAL \$ FOR FUEL ADJUSTMENT	COST IF GENERATED		FUEL SAVINGS (9B)-(8)
								(A) CENTS PER KWH	(B) DOLLARS	
ACTUAL	VARIOUS	SCH. - J	4,234.0	0.0	4,234.0	12.944	548,031.26	13.326	564,225.22	16,193.96
Jan-21	TOTAL		4,234.0	0.0	4,234.0	12.944	548,031.26	13.326	564,225.22	16,193.96
ACTUAL	VARIOUS	SCH. - J	64,475.0	0.0	64,475.0	3.696	2,383,160.78	3.759	2,423,920.49	40,759.71
Feb-21	TOTAL		64,475.0	0.0	64,475.0	3.696	2,383,160.78	3.759	2,423,920.49	40,759.71
ACTUAL	VARIOUS	SCH. - J	78,270.0	0.0	78,270.0	4.443	3,477,145.25	5.006	3,918,277.25	441,132.00
Mar-21	TOTAL		78,270.0	0.0	78,270.0	4.443	3,477,145.25	5.006	3,918,277.25	441,132.00
ACTUAL	VARIOUS	SCH. - J	117,300.0	0.0	117,300.0	2.959	3,470,960.00	3.312	3,884,958.00	413,998.00
Apr-21	TOTAL		117,300.0	0.0	117,300.0	2.959	3,470,960.00	3.312	3,884,958.00	413,998.00
ACTUAL	VARIOUS	SCH. - J	258,930.0	0.0	258,930.0	3.586	9,286,373.47	3.957	10,245,597.41	959,223.94
May-21	TOTAL		258,930.0	0.0	258,930.0	3.586	9,286,373.47	3.957	10,245,597.41	959,223.94
ACTUAL	VARIOUS	SCH. - J	273,570.0	0.0	273,570.0	3.359	9,189,425.75	3.716	10,165,453.55	976,027.80
Jun-21	TOTAL		273,570.0	0.0	273,570.0	3.359	9,189,425.75	3.716	10,165,453.55	976,027.80
ESTIMATED	VARIOUS	SCH. - J	271,550.0	0.0	271,550.0	4.228	11,480,270.00	5.332	14,480,050.00	2,999,780.00
Jul-21	TOTAL		271,550.0	0.0	271,550.0	4.228	11,480,270.00	5.332	14,480,050.00	2,999,780.00
ESTIMATED	VARIOUS	SCH. - J	271,700.0	0.0	271,700.0	4.227	11,484,420.00	5.322	14,458,780.00	2,974,360.00
Aug-21	TOTAL		271,700.0	0.0	271,700.0	4.227	11,484,420.00	5.322	14,458,780.00	2,974,360.00
ESTIMATED	VARIOUS	SCH. - J	262,540.0	0.0	262,540.0	4.039	10,604,920.00	5.181	13,600,890.00	2,995,970.00
Sep-21	TOTAL		262,540.0	0.0	262,540.0	4.039	10,604,920.00	5.181	13,600,890.00	2,995,970.00
ESTIMATED	VARIOUS	SCH. - J	267,060.0	0.0	267,060.0	4.130	11,029,890.00	5.316	14,196,940.00	3,167,050.00
Oct-21	TOTAL		267,060.0	0.0	267,060.0	4.130	11,029,890.00	5.316	14,196,940.00	3,167,050.00
ESTIMATED	VARIOUS	SCH. - J	72,880.0	0.0	72,880.0	3.575	2,605,660.00	5.113	3,726,530.00	1,120,870.00
Nov-21	TOTAL		72,880.0	0.0	72,880.0	3.575	2,605,660.00	5.113	3,726,530.00	1,120,870.00
ESTIMATED	VARIOUS	SCH. - J	2,040.0	0.0	2,040.0	5.515	112,500.00	31.914	651,050.00	538,550.00
Dec-21	TOTAL		2,040.0	0.0	2,040.0	5.515	112,500.00	31.914	651,050.00	538,550.00
TOTAL										
Jan-21										
THRU	VARIOUS	SCH. - J	1,944,549.0	0.0	1,944,549.0	3.892	75,672,756.51	4.747	92,316,671.92	16,643,915.41
Dec-21	TOTAL		1,944,549.0	0.0	1,944,549.0	3.892	75,672,756.51	4.747	92,316,671.92	16,643,915.41

EXHIBIT TO THE TESTIMONY OF M. ASHLEY SIZEMORE

DOCUMENT NO. 4

CAPACITY COST RECOVERY NO MIDCOURSE

ACTUAL / ESTIMATED

JANUARY 2021 THROUGH DECEMBER 2021

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2021 THROUGH DECEMBER 2021

1.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2020 THROUGH DECEMBER 2020	(\$3,354,779)
2.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2021 THROUGH DECEMBER 2021	<u>(6,273,850)</u>
3.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2022 THROUGH DECEMBER 2022	<u><u>(\$9,628,629)</u></u>

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
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 UNIT POWER CAPACITY CHARGES	2,069,886	1,125,101	385,048	704,682	(152,499)	1,179,112	1,176,770	1,176,770	706,062	706,062	353,031	0	9,430,025
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3 (UNIT POWER CAPACITY REVENUES)	(16,605)	(45,584)	(79,683)	(82,822)	(68,009)	(57,180)	(69,183)	(69,183)	(69,183)	(69,183)	(69,183)	(307,601)	(1,003,399)
4 TOTAL CAPACITY DOLLARS	2,053,281	1,079,517	305,365	621,860	(220,508)	1,121,932	1,107,587	1,107,587	636,879	636,879	283,848	(307,601)	8,426,626
5 SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6 JURISDICTIONAL CAPACITY DOLLARS	2,053,281	1,079,517	305,365	621,860	(220,508)	1,121,932	1,107,587	1,107,587	636,879	636,879	283,848	(307,601)	8,426,626
7 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	28,366	28,712	28,523	30,704	33,405	36,878	37,942	37,791	39,726	36,578	31,114	29,493	399,232
8 PRIOR PERIOD TRUE-UP PROVISION	147,623	147,623	147,623	147,623	147,623	147,623	147,623	147,623	147,623	147,623	147,623	147,627	1,771,480
9 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	175,989	176,335	176,146	178,327	181,028	184,501	185,565	185,414	187,349	184,201	178,737	177,120	2,170,712
10 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 9 - Line 6)	(1,877,292)	(903,182)	(129,219)	(443,533)	401,536	(937,431)	(922,022)	(922,173)	(449,530)	(452,678)	(105,111)	484,721	(6,255,914)
11 INTEREST PROVISION FOR MONTH	(234)	(372)	(384)	(419)	(270)	(291)	(1,310)	(2,549)	(2,817)	(3,009)	(3,147)	(3,134)	(17,936)
12 ADJUSTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
13 TRUE-UP AND INT. PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(1,583,299)	(3,608,448)	(4,659,625)	(4,936,851)	(5,528,426)	(5,274,783)	(6,360,128)	(7,431,083)	(8,503,428)	(9,103,398)	(9,706,708)	(9,962,589)	(1,583,299)
14 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,623)	(147,627)	(1,771,480)
15 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 10 - 14)	(3,608,448)	(4,659,625)	(4,936,851)	(5,528,426)	(5,274,783)	(6,360,128)	(7,431,083)	(8,503,428)	(9,103,398)	(9,706,708)	(9,962,589)	(9,628,629)	(9,628,629)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
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 BEGINNING TRUE-UP AMOUNT	(1,583,299)	(3,608,448)	(4,659,625)	(4,936,851)	(5,528,426)	(5,274,783)	(6,360,128)	(7,431,083)	(8,503,428)	(9,103,398)	(9,706,708)	(9,962,589)	(1,583,299)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(3,608,214)	(4,659,253)	(4,936,467)	(5,528,007)	(5,274,513)	(6,359,837)	(7,429,773)	(8,500,879)	(9,100,581)	(9,703,699)	(9,959,442)	(9,625,495)	(9,610,693)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT (LINE 1 + LINE 2)	(5,191,514)	(8,267,702)	(9,596,093)	(10,464,859)	(10,802,940)	(11,634,621)	(13,789,902)	(15,931,963)	(17,604,010)	(18,807,098)	(19,666,151)	(19,588,085)	(11,193,993)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(2,595,757)	(4,133,851)	(4,798,046)	(5,232,429)	(5,401,470)	(5,817,310)	(6,894,951)	(7,965,981)	(8,802,005)	(9,403,549)	(9,833,075)	(9,794,042)	(5,596,996)
5 INTEREST RATE % - 1ST DAY OF MONTH	0.100	0.120	0.090	0.110	0.070	0.040	0.080	0.380	0.380	0.380	0.380	0.380	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	0.120	0.090	0.110	0.070	0.040	0.080	0.380	0.380	0.380	0.380	0.380	0.380	NA
7 TOTAL (LINE 5 + LINE 6)	0.220	0.210	0.200	0.180	0.110	0.120	0.460	0.760	0.760	0.760	0.760	0.760	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	0.110	0.105	0.100	0.090	0.055	0.060	0.230	0.380	0.380	0.380	0.380	0.380	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.009	0.009	0.008	0.008	0.005	0.005	0.019	0.032	0.032	0.032	0.032	0.032	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(234)	(372)	(384)	(419)	(270)	(291)	(1,310)	(2,549)	(2,817)	(3,009)	(3,147)	(3,134)	(17,936)

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

SCHEDULE E12

CONTRACT	TERM		CONTRACT TYPE	
	START	END		
SEMINOLE ELECTRIC **	6/1/1992	-----	LT	QF = QUALIFYING FACILITY LT = LONG TERM ST = SHORT-TERM ** THREE YEAR NOTICE REQUIRED FOR TERMINATION.
FLORIDA MUNICIPAL POWER AGENCY	12/1/2020	2/28/2021	ST	
ORLANDO UTILITIES COMMISSION	12/1/2020	2/28/2021	ST	
FLORIDA POWER & LIGHT	12/1/2020	2/28/2021	ST	
ORLANDO UTILITIES COMMISSION	1/1/2021	1/31/2021	ST	

CONTRACT	ACT	ACT	ACT	ACT	ACT	ACT	EST	EST	EST	EST	EST	EST
	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
SEMINOLE ELECTRIC	1.9	7.0	10.5	9.1	5.9	6.6	10.0	10.0	10.0	10.0	10.0	10.0
FLORIDA MUNICIPAL POWER AGENCY	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ORLANDO UTILITIES COMMISSION	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FLORIDA POWER & LIGHT	160.0	160.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ORLANDO UTILITIES COMMISSION	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

CAPACITY	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
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ORLANDO UTILITIES COMMISSION
FLORIDA POWER & LIGHT
DUKE ENERGY FLORIDA

FLORIDA MUNICIPAL POWER AGENCY
JACKSONVILLE ELECTRIC AUTHORITY
SUBTOTAL CAPACITY PURCHASES

SEMINOLE ELECTRIC - D
DUKE ENERGY FLORIDA - MA
FLORIDA POWER & LIGHT - MA
ORLANDO UTILITIES COMMISSION - MA
EXGEN - MA
THE ENERGY AUTHORITY - MA
EDF TRADING - MA
RAINBOW ENERGY - MA
SUBTOTAL CAPACITY SALES

TOTAL PURCHASES AND (SALES)	2,053,281	1,079,517	305,365	621,860	(220,508)	1,121,932	1,107,587	1,107,587	636,879	636,879	283,848	(307,601)	8,426,626
TOTAL CAPACITY	2,053,281	1,079,517	305,365	621,860	(220,508)	1,121,932	1,107,587	1,107,587	636,879	636,879	283,848	(307,601)	8,426,626

**EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE**

DOCUMENT NO. 1

**PROJECTED CAPACITY COST RECOVERY
JANUARY 2022 - DECEMBER 2022
AND
SCHEDULE E12**

**TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2022 THROUGH DECEMBER 2022
PROJECTED**

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	AVG 12 CP LOAD FACTOR AT METER	PROJECTED SALES AT METER	PROJECTED AVG 12 CP AT METER	DEMAND LOSS EXPANSION FACTOR	ENERGY LOSS EXPANSION FACTOR	PROJECTED SALES AT GENERATION	PROJECTED AVG 12 CP AT GENERATION	PERCENTAGE OF SALES AT GENERATION	PERCENTAGE OF DEMAND AT GENERATION	12 CP & 1/13 AVG DEMAND FACTOR
RATE CLASS	(%)	(MWH)	(MW)			(MWH)	(MW)	(%)	(%)	(%)
RS,RSVP	52.98%	9,728,165	2,096	1.07447	1.05324	10,246,140	2,252	49.26%	59.49%	58.70%
GS, CS	62.08%	953,392	175	1.07447	1.05323	1,004,139	188	4.83%	4.97%	4.96%
GSD Optional	4.10%	417,435	60	1.06971	1.04880	437,805	64	2.11%	1.69%	1.72%
GSD, SBF	75.51%	7,681,911	1,101	1.06971	1.04880	8,056,777	1,178	38.74%	31.11%	31.70%
IS,SBI	105.90%	920,157	99	1.03064	1.01680	935,613	102	4.50%	2.69%	2.83%
LS1	802.58%	110,703	2	1.07447	1.05324	116,598	2	0.56%	0.05%	0.09%
TOTAL		19,811,763	3,533			20,797,072	3,786	100.00%	100.00%	100.00%

- (1) AVG 12 CP load factor based on 2021 projected calendar data.
(2) Projected MWH sales for the period January 2022 thru December 2022.
(3) Based on 12 months average CP at meter.
(4) Based on 2021 projected demand losses.
(5) Based on 2021 projected energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Based on 12 months average percentage of sales at generation.
(9) Based on 12 months average percentage of demand at generation.
(10) Col (8) * 0.0769 + Col (9) * 0.9231

**TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2022 THROUGH DECEMBER 2022
PROJECTED**

	January	February	March	April	May	June	July	August	September	October	November	December	Total
1 UNIT POWER CAPACITY CHARGES	0	0	0	706,062	706,062	706,062	776,668	776,668	776,668	776,668	706,062	0	5,930,921
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3 (UNIT POWER CAPACITY REVENUES)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,178)	(746,114)
4 TOTAL CAPACITY DOLLARS	(\$62,176)	(\$62,176)	(\$62,176)	\$643,886	\$643,886	\$643,886	\$714,492	\$714,492	\$714,492	\$714,492	\$643,886	(\$62,178)	\$5,184,807
5 SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6 JURISDICTIONAL CAPACITY DOLLARS	(\$62,176)	(\$62,176)	(\$62,176)	\$643,886	\$643,886	\$643,886	\$714,492	\$714,492	\$714,492	\$714,492	\$643,886	(\$62,178)	\$5,184,806
7 ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2021 - DEC. 2021													25,180
8 SOBRA 3 TRUE-UP													(85,648)
9 TOTAL													\$5,124,338
10 REVENUE TAX FACTOR													1.00072
11 TOTAL RECOVERABLE CAPACITY DOLLARS													<u>\$5,128,028</u>

**TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2022 THROUGH DECEMBER 2022
PROJECTED**

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION (%)	(2) PERCENTAGE OF DEMAND AT GENERATION (%)	(3) ENERGY RELATED COSTS (\$)	(4) DEMAND RELATED COSTS (\$)	(5) TOTAL CAPACITY COSTS (\$)	(6) PROJECTED SALES AT METER (MWH)	(7) EFFECTIVE AT SECONDARY LEVEL (MWH)	(8) BILLING KW LOAD FACTOR (%)	(9) PROJECTED BILLED KW AT METER (kw)	(10) CAPACITY RECOVERY FACTOR (\$/kw)	(11) CAPACITY RECOVERY FACTOR (\$/kwh)
RS	49.26%	59.49%	194,254	2,816,068	3,010,322	9,728,165	9,728,165				0.00031
GS, CS	4.83%	4.97%	19,047	235,264	254,311	953,392	953,392				0.00027
GSD, SBF											
Secondary						6,307,319	6,307,319			0.09	
Primary						1,369,359	1,355,666			0.09	
Transmission						5,233	5,128			0.09	
GSD, SBF - Standard	38.74%	31.11%	152,769	1,472,649	1,625,418	7,681,911	7,668,113	58.83%	17,854,692		
GSD - Optional	2.11%	1.69%	8,321	79,999	88,320						
Secondary						406,871	406,871				0.00021
Primary						10,564	10,459				0.00021
Transmission						0	0				0.00021
IS, SBI											
Primary						189,417	187,523			0.07	
Transmission						730,740	716,125			0.07	
Total IS, SBI	4.50%	2.69%	17,746	127,336	145,082	920,157	903,648	63.63%	1,945,276		
LS1	0.56%	0.05%	2,208	2,367	4,575	110,703	110,703				0.00004
TOTAL	100.00%	100.00%	394,345	4,733,683	5,128,028	19,811,763	19,781,351				0.00026

(1) Obtained from page 1.

(2) Obtained from page 1.

(3) Total capacity costs * 0.0769 * Col (1).

(4) Total capacity costs * 0.9231 * Col (2).

(5) Col (3) + Col (4).

(6) Projected kWh sales for the period January 2022 through December 2022.

(7) Projected kWh sales at secondary for the period January 2022 through December 2022.

(8) Col 7 / (Col 9 * 730)*1000

(9) Projected kw demand for the period January 2022 through December 2022.

(10) Total Col (5) / Total Col (9).

(11) {Col (5) / Total Col (7)} / 1000.

TAMPA ELECTRIC COMPANY

SCHEDULE E12

CAPACITY COSTS

ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

CONTRACT	TERM		CONTRACT TYPE
	START	END	
SEMINOLE ELECTRIC **	6/1/1992	-----	LT
QF = QUALIFYING FACILITY LT = LONG TERM ST = SHORT-TERM ** THREE YEAR NOTICE REQUIRED FOR TERMINATION.			

CONTRACT	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	
SEMINOLE ELECTRIC	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	
CAPACITY	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)

VARIOUS
SUBTOTAL CAPACITY PURCHASES

SEMINOLE ELECTRIC - D
VARIOUS MARKET BASED
SUBTOTAL CAPACITY SALES

TOTAL PURCHASES AND (SALES)	(62,176)	(62,176)	(62,176)	643,886	643,886	643,886	714,492	714,492	714,492	714,492	643,886	(62,178)	5,184,807
TOTAL CAPACITY	(\$62,176)	(\$62,176)	(\$62,176)	\$643,886	\$643,886	\$643,886	\$714,492	\$714,492	\$714,492	\$714,492	\$643,886	(\$62,178)	\$5,184,807

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2022 - DECEMBER 2022

**SCHEDULES E1 THROUGH E10
SCHEDULE H1**

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1 Cost Recovery Clause Calculation	(JAN. 2022 - DEC. 2022)
3	Schedule E1-A Calculation of Total True-Up	(")
4	Schedule E1-C GPIF & True-Up Adj. Factors	(")
5	Schedule E1-D Fuel Adjustment Factor for TOD	(")
6	Schedule E1-E Fuel Recovery Factor-with Line Losses	(")
7	Schedule E2 Cost Recovery Clause Calculation (By Month)	(")
8-9	Schedule E3 Generating System Comparative Data	(")
10-33	Schedule E4 System Net Generation & Fuel Cost	(")
34-35	Schedule E5 Inventory Analysis	(")
36-37	Schedule E6 Power Sold	(")
38	Schedule E7 Purchased Power	(")
39	Schedule E8 Energy Payment to Qualifying Facilities	(")
40	Schedule E9 Economy Energy Purchases	(")
41	Schedule E10 Residential Bill Comparison	(")
42	Schedule H1 Generating System Comparative Data	(JAN. - DEC. 2019-2022)

**TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022**

SCHEDULE E1

	DOLLARS	MWH	CENTS/KWH
1. Fuel Cost of System Net Generation (E3)	591,244,371	20,728,070	2.85239
2. Nuclear Fuel Disposal Cost	0	0	0.00000
3. Coal Car Investment	0	0	0.00000
4a. Adjustment	0	20,728,070 ⁽¹⁾	0.00000
4b. Adjustment	0	0	0.00000
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)	591,244,371	20,728,070	2.85239
6. Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	0	0	0.00000
7. Energy Cost of Economy Purchases (E9)	6,737,130	104,970	6.41815
8. Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9. Energy Payments to Qualifying Facilities (E8)	1,866,220	68,840	2.71095
10. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)	8,603,350	173,810	4.94986
11. TOTAL AVAILABLE MWH (LINE 5 + LINE 10)		20,901,880	
12. Fuel Cost of Schedule D Sales - Jurisd. (E6)	980,190	35,040	2.79735
13. Fuel Cost of Market Based Sales - Jurisd. (E6)	0	0	0.00000
14. Gains on Sales	69,080	NA	NA
15. TOTAL FUEL COST AND GAINS OF POWER SALES	1,049,270	35,040	2.99449
16. Net Inadvertant Interchange		0	
17. Wheeling Received Less Wheeling Delivered		0	
18. Interchange and Wheeling Losses		1,198	
19. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)	598,798,451	20,865,642	2.86978
20. Net Unbilled	NA ^{(1)(a)}	NA ^(a)	NA
21. Company Use	1,033,121 ⁽¹⁾	36,000	0.00522
22. T & D Losses	29,337,798 ⁽¹⁾	1,022,301	0.14812
23. System MWH Sales	598,798,451	19,807,340	3.02311
24. Wholesale MWH Sales	0	0	0.00000
25. Jurisdictional MWH Sales	598,798,451	19,807,340	3.02311
26. Jurisdictional Loss Multiplier			1.00000
27. Jurisdictional MWH Sales Adjusted for Line Loss	598,798,451	19,807,340	3.02311
28. Optimization Mechanism{2}	1,285,228	19,807,340	0.00649
29. True-up (2)	325,418	19,807,340	0.00164
30. Total Jurisdictional Fuel Cost (Excl. GPIF)	600,409,097	19,807,340	3.03125
31. Revenue Tax Factor			1.00072
32. Fuel Factor (Excl. GPIF) Adjusted for Taxes	600,841,392	19,807,340	3.03343
33. GPIF Adjusted for Taxes (2)	3,673,726	19,807,340	0.01855
34. Fuel Factor Adjusted for Taxes Including GPIF	604,515,118	19,807,340	3.05198
35 Fuel Factor Rounded to Nearest .001 cents per KWH			3.052

^(a) Data not available at this time.

⁽¹⁾ Included For Informational Purposes Only

⁽²⁾ Calculation Based on Jurisdictional MWH Sales

**TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022**

SCHEDULE E1-A

1. ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2021 - December 2021 (6 months actual, 6 months estimated)	(\$44,617,507)
2. PROJECTED OVER/UNDER-RECOVERY TRUE-UP INCLUDED IN SEPTEMBER - DECEMBER 2021 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	(\$49,015,848)
3. DIFFERENCE IN 2020 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2021 RATES AND AMOUNT COLLECTED IN 2021 (\$25,479,055 under-recovery less (\$2,123,255) refunded each month January through August 2021)	<u>(\$8,493,015)</u>
4. ACTUAL-ESTIMATED 2021 OVER/(UNDER) RECOVERY (Line 1 - Line 2 + Line 3)	(\$4,094,674)
5. FINAL TRUE-UP (January 2020 - December 2020) (Per True-Up filed April 2, 2021)	<u>3,769,256</u>
6. TOTAL OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2022 (Line 4 + Line 5) To be included in the 12-month projected period January 2022 through December 2022 (2022 Schedule E1, line 29)	<u><u>(\$325,418)</u></u>
7. JURISDICTIONAL MWH SALES (Projected January 2022 through December 2022)	19,807,340
8. TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,776,928)	0.0016

**TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022**

SCHEDULE E1-C

1. TOTAL AMOUNT OF ADJUSTMENTS

A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2022 through December 2022)	\$3,673,726
B. TRUE-UP OVER / (UNDER) RECOVERED (January 2022 through December 2022)	(\$325,418)
C. OPTIMIZATION MECHANISM GAIN / (LOSS) (January 2022 through December 2022)	\$1,285,228

2. TOTAL SALES (January 2022 through December 2022)	19,807,340 MWh
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3. ADJUSTMENT FACTORS

A. GENERATING PERFORMANCE INCENTIVE FACTOR (Using Effective MWh Sales of 19,776,928)	0.0186 Cents/kWh
B. TRUE-UP FACTOR (Using Effective MWh Sales of 19,776,928)	0.0016 Cents/kWh
C. OPTIMIZATION MECHANISM FACTOR (Using Effective MWh Sales of 19,776,928)	0.0065 Cents/kWh

**DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022**

SCHEDULE E1-D

			NET ENERGY FOR LOAD (%)	FUEL COST (%)
	ON PEAK		30.09	\$22.07
	OFF PEAK		69.91	\$19.58
			100.00	1.1272
	TOTAL	ON PEAK		OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)			
2	MWH Sales (Jurisd)	(Sch E1 line 25)		
2a	Effective MWH Sales (Jurisd)	(Sch E1 line 25)		
3	Cost Per KWH Sold	(line 1 / line 2)		
4	Jurisdictional Loss Factor			
5	Jurisdictional Fuel Factor			
6	True-Up	NA		
7	Optimization Mechanism	\$325.418		
8	TOTAL	\$1,285,228		
9	Revenue Tax Factor	\$600,409,097		
10	Recovery Factor	1.00072		
11	GPIF Factor	(line 8 x line 9) / line 2a / 10		
12	Recovery Factor Including GPIF	3.0381		
13	Recovery Factor Rounded to the Nearest .001 cents/KWH	(Sch E1-C line 3A) (line 10 + line 11)	3.3184	2.944
			3.318	2.944
14	Hours: ON PEAK	25.60%		
15	OFF PEAK	74.40%		
		100.00%		

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Line Loss	Secondary
Distribution Secondary	17,502,027		17,502,027
Distribution Primary	1,569,341	0.99	1,553,647
Transmission	735,973	0.98	721,254
Total	19,807,340		19,776,928
		Standard	On-Peak Off-Peak
	Distribution Secondary	3,057	3,318 2,944
	Distribution Primary	3,026	3,285 2,915
	Transmission	2,996	3,252 2,885
	RS 1st Tier	2,745	
	RS 2nd Tier	3,745	
	Lighting	3,008	

SCHEDULE E1-E

**TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022**

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		2.745	3.745
Distribution Secondary	3.057		
Distribution Primary	3.026		
Transmission	2.996		
Lighting Service ⁽¹⁾	3.008		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.318		
Distribution Secondary - Off-Peak	2.944		
Distribution Primary - On-Peak	3.285		
Distribution Primary - Off-Peak	2.915		
Transmission - On-Peak	3.252		
Transmission - Off-Peak	2.885		

(1) Lighting service is based on distribution secondary, 17% on-peak and 83% off-peak

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Jan-22	Feb-22	Mar-22	Apr-22	May-22	ESTIMATED Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	TOTAL PERIOD
1. Fuel Cost of System Net Generation	50,628,655	43,712,330	45,704,776	43,168,114	49,710,665	56,554,931	58,231,044	59,752,774	53,251,426	47,781,768	39,999,180	42,748,708	591,244,371
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold ⁽¹⁾	96,568	87,586	92,414	81,142	86,998	94,887	87,362	91,825	86,173	87,051	73,242	84,022	1,049,270
4. Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	149,230	139,130	164,470	141,730	130,060	169,370	150,520	173,790	184,140	165,380	154,990	143,410	1,866,220
7. Energy Cost of Economy Purchases	14,270	10,250	5,180	1,700	26,170	480,100	609,210	364,870	4,111,460	1,108,180	1,320	4,420	6,737,130
8. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
9. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10. TOTAL FUEL & NET POWER TRANSACTIONS	50,695,587	43,774,124	45,782,012	43,230,402	49,779,897	57,109,514	58,903,412	60,199,609	57,460,853	48,968,277	40,082,248	42,812,516	598,798,451
11. Jurisdictional MWh Sold	1,484,835	1,360,586	1,350,140	1,437,866	1,599,548	1,857,040	1,948,278	1,942,542	2,005,956	1,835,903	1,536,267	1,448,380	19,807,340
12. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
13. Jurisdictional Total Fuel & Net Power Transactions (Line 10 * Line 12)	50,695,587	43,774,124	45,782,012	43,230,402	49,779,897	57,109,514	58,903,412	60,199,609	57,460,853	48,968,277	40,082,248	42,812,516	598,798,451
14. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
15. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 13 * Line 14)	50,695,587	43,774,124	45,782,012	43,230,402	49,779,897	57,109,514	58,903,412	60,199,609	57,460,853	48,968,277	40,082,248	42,812,516	598,798,451
16. Cost Per kWh Sold (Cents/kWh)	3.4142	3.2173	3.3909	3.0066	3.1121	3.0753	3.0234	3.0990	2.8645	2.6673	2.6091	2.9559	3.0231
17. Optimization Mechanism (Cents/kWh) ⁽²⁾	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065
18. True-up (Cents/kWh) ⁽²⁾	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016
19. Total (Cents/kWh) (Line 16+17+18)	3.4223	3.2254	3.3990	3.0147	3.1202	3.0834	3.0315	3.1071	2.8726	2.6754	2.6172	2.9640	3.0312
20. Revenue Tax Factor	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
21. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.4248	3.2277	3.4014	3.0169	3.1224	3.0856	3.0337	3.1093	2.8747	2.6773	2.6191	2.9661	3.0334
22. GPIF Adjusted for Taxes (Cents/kWh) ⁽²⁾	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186
23. TOTAL RECOVERY FACTOR (LINE 21+22)	3.4434	3.2463	3.4200	3.0355	3.1410	3.1042	3.0523	3.1279	2.8933	2.6959	2.6377	2.9847	3.0520
24. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	3.443	3.246	3.420	3.036	3.141	3.104	3.052	3.128	2.893	2.696	2.638	2.985	3.052

⁽¹⁾ Includes Gains
⁽²⁾ Based on Effective MWh Sales shown on Schedule E1-C

**TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH JUNE 2022**

SCHEDULE E3

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
FUEL COST OF SYSTEM NET GENERATION (\$)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	91,149	90,787	90,425	90,061	89,697	89,332
3. COAL	4,505,889	3,989,914	3,561,514	3,175,693	4,571,140	4,730,807
4. NATURAL GAS	46,031,617	39,631,629	42,052,837	39,902,360	45,049,828	51,734,792
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL (\$)	50,628,655	43,712,330	45,704,776	43,168,114	49,710,665	56,554,931
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	300	300	300	300	300	300
10. COAL	136,740	118,250	106,710	92,550	136,640	144,780
11. NATURAL GAS	1,242,630	1,086,820	1,214,550	1,278,940	1,470,280	1,643,510
12. SOLAR	127,340	142,060	175,360	218,220	240,250	206,030
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	1,507,010	1,347,430	1,496,920	1,590,010	1,847,470	1,994,620
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	665	665	665	665	665	665
17. COAL (TON)	72,550	63,500	57,140	50,210	73,110	75,560
18. NATURAL GAS (MCF)	8,871,535	7,779,965	8,734,935	9,187,705	10,533,255	12,412,825
19. SOLAR	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	3,900	3,900	3,900	3,900	3,900	3,900
23. COAL	1,632,410	1,428,790	1,285,690	1,129,690	1,644,990	1,700,000
24. NATURAL GAS	9,112,610	7,990,500	8,973,090	9,437,680	10,826,040	12,738,500
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	10,748,920	9,423,190	10,262,680	10,571,270	12,474,930	14,442,400
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.02	0.02
30. COAL	9.07	8.78	7.13	5.82	7.40	7.25
31. NATURAL GAS	82.46	80.66	81.14	80.44	79.58	82.40
32. SOLAR	8.45	10.54	11.71	13.72	13.00	10.33
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT						
35. HEAVY OIL (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL (\$/BBL)	137.07	136.52	135.98	135.43	134.88	134.33
37. COAL (\$/TON)	62.11	62.83	62.33	63.25	62.52	62.61
38. NATURAL GAS (\$/MCF)	5.19	5.09	4.81	4.34	4.28	4.17
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU (\$/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	23.37	23.28	23.19	23.09	23.00	22.91
43. COAL	2.76	2.79	2.77	2.81	2.78	2.78
44. NATURAL GAS	5.05	4.96	4.69	4.23	4.16	4.06
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL (\$/MMBTU)	4.71	4.64	4.45	4.08	3.98	3.92
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000
50. COAL	11,938	12,083	12,048	12,206	12,039	11,742
51. NATURAL GAS	7,333	7,352	7,388	7,379	7,363	7,751
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	7,133	6,993	6,856	6,649	6,752	7,241
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	30.38	30.26	30.14	30.02	29.90	29.78
57. COAL	3.30	3.37	3.34	3.43	3.35	3.27
58. NATURAL GAS	3.70	3.65	3.46	3.12	3.06	3.15
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	3.36	3.24	3.05	2.71	2.69	2.84

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2022 THROUGH DECEMBER 2022

SCHEDULE E3

	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	TOTAL
FUEL COST OF SYSTEM NET GENERATION (\$)							
1. HEAVY OIL	0	0	0	0	0	0	0
2. LIGHT OIL	88,973	88,618	88,267	87,922	87,582	87,246	1,070,059
3. COAL	5,010,894	5,123,910	4,979,203	509,008	3,930,668	4,423,948	48,512,588
4. NATURAL GAS	53,131,177	54,540,246	48,183,956	47,184,838	35,980,930	38,237,514	541,661,724
5. SOLAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL (\$)	58,231,044	59,752,774	53,251,426	47,781,768	39,999,180	42,748,708	591,244,371
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	0	0	0	0	0	0	0
9. LIGHT OIL	300	300	300	300	300	300	3,600
10. COAL	154,270	158,760	154,310	15,880	114,030	130,860	1,463,780
11. NATURAL GAS	1,719,190	1,762,600	1,604,070	1,634,990	1,232,580	1,265,350	17,155,510
12. SOLAR	200,630	193,910	167,470	166,660	129,810	137,440	2,105,180
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	2,074,390	2,115,570	1,926,150	1,817,830	1,476,720	1,533,950	20,728,070
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	0	0	0	0	0	0	0
16. LIGHT OIL (BBL)	665	665	665	665	665	665	7,980
17. COAL (TON)	79,890	81,600	79,240	8,090	62,470	70,290	773,650
18. NATURAL GAS (MCF)	12,677,295	13,146,505	11,541,635	11,241,335	8,135,455	8,409,095	122,671,540
19. SOLAR	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	0	0	0	0	0	0	0
22. LIGHT OIL	3,900	3,900	3,900	3,900	3,900	3,900	46,800
23. COAL	1,797,510	1,836,030	1,782,840	182,090	1,405,660	1,581,590	17,407,290
24. NATURAL GAS	13,015,500	13,496,970	11,842,940	11,543,620	8,350,810	8,638,150	125,966,410
25. SOLAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	14,816,910	15,336,900	13,629,680	11,729,610	9,760,370	10,223,640	143,420,500
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.01	0.01	0.02	0.02	0.02	0.02	0.02
30. COAL	7.44	7.50	8.01	0.87	7.72	8.53	7.06
31. NATURAL GAS	82.88	83.32	83.28	89.94	83.47	82.49	82.76
32. SOLAR	9.67	9.17	8.69	9.17	8.79	8.96	10.16
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT							
35. HEAVY OIL (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL (\$/BBL)	133.79	133.26	132.73	132.21	131.70	131.20	134.09
37. COAL (\$/TON)	62.72	62.79	62.84	62.92	62.92	62.94	62.71
38. NATURAL GAS (\$/MCF)	4.19	4.15	4.17	4.20	4.42	4.55	4.42
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU (\$/MMBTU)							
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	22.81	22.72	22.63	22.54	22.46	22.37	22.86
43. COAL	2.79	2.79	2.79	2.80	2.80	2.80	2.79
44. NATURAL GAS	4.08	4.04	4.07	4.09	4.31	4.43	4.30
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL (\$/MMBTU)	3.93	3.90	3.91	4.07	4.10	4.18	4.12
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	0	0	0	0	0	0	0
49. LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000	13,000
50. COAL	11,652	11,565	11,554	11,467	12,327	12,086	11,892
51. NATURAL GAS	7,571	7,657	7,383	7,060	6,775	6,827	7,343
52. SOLAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	7,143	7,250	7,076	6,453	6,609	6,665	6,919
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	29.66	29.54	29.42	29.31	29.19	29.08	29.72
57. COAL	3.25	3.23	3.23	3.21	3.45	3.38	3.31
58. NATURAL GAS	3.09	3.09	3.00	2.89	2.92	3.02	3.16
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	2.81	2.82	2.76	2.63	2.71	2.79	2.85

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	270	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	190	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,860	256.3	-	256.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	9,780	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,120	18.3	-	18.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,290	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,380	18.5	-	18.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,670	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,430	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,470	17.6	-	17.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,490	20.7	-	20.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,240	22.1	-	22.1	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,590	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,480.0	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	7,320.0	13.2	-	13.2	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	10,380.0	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	10,380.0	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	127,340	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	355	13,490	5.1	-	-	-	GAS	155,170	1,027,969	159,510.0	805,129	5.97	5.19
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	355	13,490	5.1	82.1	52.8	11,824	-	-	-	159,510.0	805,129	5.97	-
24. B.B.#4 (GAS)	160	7,200	6.0	-	-	-	GAS	83,580	1,027,997	85,920.0	433,670	6.02	5.19
25. B.B.#4 (COAL)	432	136,740	42.5	-	-	-	COAL	72,550	22,500,482	1,632,410.0	4,505,889	3.30	62.11
26. BIG BEND #4 TOTAL	432	143,940	44.8	89.3	48.9	11,938	-	-	-	1,718,330.0	4,939,559	3.43	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	7,100	1,028,169	7,300.0	36,840	-	5.19
28. B.B.C.T.#4 TOTAL	61	70	0.2	98.3	57.4	13,000	GAS	890	1,022,472	910.0	4,618	6.60	5.19
29. B.B.C.T.#5 TOTAL	350	7,140	2.7	96.0	63.8	9,821	GAS	68,210	1,028,002	70,120.0	353,920	4.96	5.19
30. B.B.C.T.#6 TOTAL	350	3,250	1.2	96.1	58.0	9,966	GAS	31,520	1,027,602	32,390.0	163,547	5.03	5.19
31. BIG BEND STATION TOTAL	1,898	167,890	11.9	74.3	49.8	11,801	-	-	-	1,981,260.0	6,303,613	3.75	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	230	5,380	3.1	-	73.1	8,959	GAS	46,880	1,028,157	48,200.0	243,246	4.52	5.19
34. POLK #1 TOTAL	230	5,380	3.1	93.8	73.1	8,959	-	-	-	48,200.0	243,246	4.52	-
35. POLK #2 ST DUCT FIRING	120	2,040	2.3	-	85.0	8,157	GAS	16,190	1,027,795	16,640.0	84,005	4.12	5.19
36. POLK #2 ST W/O DUCT FIRING	360	623,040	-	-	-	-	-	4,198,315	1,028,003	4,315,880.0	21,783,742	3.50	5.19
37. POLK #2 ST TOTAL	480	625,080	175.0	-	173.6	6,931	GAS	-	-	4,332,520.0	21,867,747	3.50	-
38. POLK #2 CT (GAS)	180	930	0.7	-	64.6	11,591	GAS	10,490	1,027,645	10,780.0	54,429	5.85	5.19
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,643	30.43	137.07
40. POLK #2 TOTAL	⁽⁴⁾ 180	1,080	0.8	-	66.4	11,787	-	-	-	12,730.0	100,072	9.27	-
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	45,506	30.34	137.07
43. POLK #3 TOTAL	⁽⁴⁾ 180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,506	30.34	-

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TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,200	626,310	70.2	97.4	172.2	6,941	-	-	-	4,347,200.0	22,013,325	3.51	-
47. POLK STATION TOTAL	1,430	631,690	59.4	96.8	168.2	6,958	-	-	-	4,395,400.0	22,256,571	3.52	-
48. BAYSIDE #1	792	343,790	58.3	96.6	61.1	7,309	GAS	2,444,440	1,027,994	2,512,870.0	12,683,434	3.69	5.19
49. BAYSIDE #2	1,047	235,990	30.3	97.3	32.7	7,863	GAS	1,805,030	1,027,994	1,855,560.0	9,365,737	3.97	5.19
50. BAYSIDE #3	61	80	0.2	98.6	65.6	12,000	GAS	930	1,032,258	960.0	4,825	6.03	5.19
51. BAYSIDE #4	61	80	0.2	98.6	65.6	12,000	GAS	930	1,032,258	960.0	4,825	6.03	5.19
52. BAYSIDE #5	61	70	0.2	98.6	57.4	13,714	GAS	930	1,032,258	960.0	4,825	6.89	5.19
53. BAYSIDE #6	61	80	0.2	98.6	65.6	11,875	GAS	930	1,021,505	950.0	4,825	6.03	5.19
54. BAYSIDE STATION TOTAL	2,083	580,090	37.4	97.2	45.1	7,537	GAS	4,253,190	1,027,995	4,372,260.0	22,068,471	3.80	5.19
55. SYSTEM TOTAL	6,289	1,507,010	32.2	76.6	79.5	7,133	-	-	-	10,748,920.0	50,628,655	3.36	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	190	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,030	300.6	-	300.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	11,280	23.9	-	23.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	11,710	23.5	-	23.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,060	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	9,310	22.8	-	22.8	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	8,520	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,790	23.0	-	23.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	7,460	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	12,120	24.1	-	24.1	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,960	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	9,920	24.7	-	24.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,020.0	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	8,450.0	16.9	-	16.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	11,990.0	34.1	-	34.1	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	11,990.0	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	142,060	24.1	-	24.1	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	355	13,500	5.7	-	-	-	GAS	155,270	1,028,016	159,620.0	790,955	5.86	5.09
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	355	13,500	5.7	48.5	52.8	11,824	-	-	-	159,620.0	790,955	5.86	-
24. B.B.#4 (GAS)	160	6,230	5.8	-	-	-	GAS	73,150	1,027,888	75,190.0	372,630	5.98	5.09
25. B.B.#4 (COAL)	432	118,250	40.7	-	-	-	COAL	63,500	22,500,630	1,428,790.0	3,989,914	3.37	62.83
26. BIG BEND #4 TOTAL	432	124,480	42.9	89.3	46.8	12,082	-	-	-	1,503,980.0	4,362,544	3.50	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	7,100	1,028,169	7,300.0	36,168	-	5.09
28. B.B.C.T.#4 TOTAL	61	10	0.0	98.3	16.4	24,000	GAS	230	1,043,478	240.0	1,172	11.72	5.10
29. B.B.C.T.#5 TOTAL	350	5,190	2.2	94.9	51.1	10,023	GAS	50,610	1,027,860	52,020.0	257,811	4.97	5.09
30. B.B.C.T.#6 TOTAL	350	1,540	0.7	96.1	55.0	9,766	GAS	14,630	1,028,025	15,040.0	74,526	4.84	5.09
31. BIG BEND STATION TOTAL	1,898	144,720	11.3	67.8	47.5	11,960	-	-	-	1,730,900.0	5,523,176	3.82	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	230	8,230	5.3	-	74.5	8,898	GAS	71,230	1,028,078	73,230.0	362,850	4.41	5.09
34. POLK #1 TOTAL	230	8,230	5.3	93.8	74.5	8,898	-	-	-	73,230.0	362,850	4.41	-
35. POLK #2 ST DUCT FIRING	120	2,260	2.8	-	75.3	8,190	GAS	18,000	1,028,333	18,510.0	91,693	4.06	5.09
36. POLK #2 ST W/O DUCT FIRING	360	555,510	-	-	-	-	-	3,742,155	1,028,001	3,846,940.0	19,062,772	3.43	5.09
37. POLK #2 ST TOTAL	480	557,770	172.9	-	172.4	6,930	GAS	-	-	3,865,450.0	19,154,465	3.43	-
38. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,462	30.31	136.52
40. POLK #2 TOTAL	⁽⁴⁾ 180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,462	30.31	-
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	45,325	30.22	136.52
43. POLK #3 TOTAL	⁽⁴⁾ 180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,325	30.22	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,200	558,070	69.2	97.4	172.1	6,933	-	-	-	3,869,350.0	19,245,252	3.45	-
47. POLK STATION TOTAL	1,430	566,300	58.9	96.8	165.7	6,962	-	-	-	3,942,580.0	19,608,102	3.46	-
48. BAYSIDE #1	792	276,720	52.0	96.6	56.4	7,348	GAS	1,978,040	1,028,002	2,033,430.0	10,076,260	3.64	5.09
49. BAYSIDE #2	1,047	217,230	30.9	97.3	32.2	7,879	GAS	1,664,970	1,027,994	1,711,580.0	8,481,462	3.90	5.09
50. BAYSIDE #3	61	100	0.2	98.6	82.0	12,000	GAS	1,170	1,025,641	1,200.0	5,960	5.96	5.09
51. BAYSIDE #4	61	100	0.2	98.6	82.0	11,500	GAS	1,120	1,026,786	1,150.0	5,705	5.71	5.09
52. BAYSIDE #5	61	100	0.2	98.6	82.0	11,500	GAS	1,120	1,026,786	1,150.0	5,705	5.71	5.09
53. BAYSIDE #6	61	100	0.2	98.6	82.0	12,000	GAS	1,170	1,025,641	1,200.0	5,960	5.96	5.09
54. BAYSIDE STATION TOTAL	2,083	494,350	35.3	97.2	42.4	7,585	GAS	3,647,590	1,027,997	3,749,710.0	18,581,052	3.76	5.09
55. SYSTEM TOTAL	6,289	1,347,430	31.9	74.7	78.4	6,993	-	-	-	9,423,190.0	43,712,330	3.24	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	330	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	250	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,060	364.3	-	364.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,260	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,750	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,290	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,050	24.5	-	24.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,120	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,280	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,770	23.9	-	23.9	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,460	29.7	-	29.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,360	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,640	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,720.0	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	9,900.0	17.9	-	17.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	14,060.0	36.2	-	36.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,060.0	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	175,360	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	355	13,510	5.1	-	-	-	GAS	155,390	1,027,994	159,740.0	748,099	5.54	4.81
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	400	13,510	4.5	82.1	46.9	11,824	-	-	-	159,740.0	748,099	5.54	-
24. B.B.#4 (GAS)	160	5,620	4.7	-	-	-	GAS	65,820	1,028,107	67,670.0	316,879	5.64	4.81
25. B.B.#4 (COAL)	432	106,710	33.2	-	-	-	COAL	57,140	22,500,700	1,285,690.0	3,561,514	3.34	62.33
26. BIG BEND #4 TOTAL	432	112,330	35.0	72.0	47.3	12,048	-	-	-	1,353,360.0	3,878,393	3.45	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	6,260	1,028,754	6,440.0	30,138	-	4.81
28. B.B.C.T.#4 TOTAL	61	10	0.0	98.3	16.4	29,000	GAS	280	1,035,714	290.0	1,348	13.48	4.81
29. B.B.C.T.#5 TOTAL	350	9,720	3.7	96.9	56.7	9,894	GAS	93,550	1,028,006	96,170.0	450,380	4.63	4.81
30. B.B.C.T.#6 TOTAL	350	4,030	1.5	96.1	52.3	10,050	GAS	39,390	1,028,180	40,500.0	189,636	4.71	4.81
31. BIG BEND STATION TOTAL	1,943	139,600	9.7	70.7	47.9	11,820	-	-	-	1,650,060.0	5,297,994	3.80	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	230	25,040	14.7	-	73.6	8,919	GAS	217,260	1,027,985	223,340.0	1,045,961	4.18	4.81
34. POLK #1 TOTAL	230	25,040	14.7	93.8	73.6	8,919	-	-	-	223,340.0	1,045,961	4.18	-
35. POLK #2 ST DUCT FIRING	120	3,610	4.0	-	79.2	8,163	GAS	28,670	1,027,904	29,470.0	138,027	3.82	4.81
36. POLK #2 ST W/O DUCT FIRING	360	510,580	-	-	-	-	-	3,440,515	1,028,003	3,536,860.0	16,563,765	3.24	4.81
37. POLK #2 ST TOTAL	480	514,190	144.2	-	166.3	6,936	GAS	-	-	3,566,330.0	16,701,792	3.25	-
38. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,281	30.19	135.98
40. POLK #2 TOTAL	⁽⁴⁾ 180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,281	30.19	-
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	45,144	30.10	135.98
43. POLK #3 TOTAL	⁽⁴⁾ 180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,144	30.10	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	(4) 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL	(4) 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,200	514,490	57.7	81.7	166.1	6,939	-	-	-	3,570,230.0	16,792,217	3.26	-
47. POLK STATION TOTAL	1,430	539,530	50.8	83.7	148.8	7,031	-	-	-	3,793,570.0	17,838,178	3.31	-
48. BAYSIDE #1	792	345,880	58.8	96.6	60.8	7,316	GAS	2,461,540	1,027,999	2,530,460.0	11,850,659	3.43	4.81
49. BAYSIDE #2	1,047	296,530	38.1	97.3	39.2	7,716	GAS	2,225,700	1,027,996	2,288,010.0	10,715,249	3.61	4.81
50. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
51. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
52. BAYSIDE #5	61	10	0.0	98.6	16.4	29,000	GAS	280	1,035,714	290.0	1,348	13.48	4.81
53. BAYSIDE #6	61	10	0.0	98.6	16.4	29,000	GAS	280	1,035,714	290.0	1,348	13.48	4.81
54. BAYSIDE STATION TOTAL	2,083	642,430	41.5	91.4	48.5	7,501	GAS	4,687,800	1,027,998	4,819,050.0	22,568,604	3.51	4.81
55. SYSTEM TOTAL	6,334	1,496,920	31.8	70.6	79.9	6,856	-	-	-	10,262,680.0	45,704,776	3.05	-

LEGEND:

B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition

⁽²⁾ Fuel burned (MM BTU) system total excludes ignition

⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	320	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	300	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,620	427.8	-	427.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	17,310	34.3	-	34.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	18,040	33.8	-	33.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	19,530	36.5	-	36.5	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	14,530	33.2	-	33.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	13,270	33.6	-	33.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	9,200	34.2	-	34.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	11,550	32.5	-	32.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	18,700	34.8	-	34.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	19,600	36.6	-	36.6	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	15,160	35.2	-	35.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	6,190.0	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	13,000.0	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	18,450.0	49.0	-	49.0	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	18,450.0	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	218,220	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	0	0.0	82.1	0.0	0	-	-	-	0.0	0	0.00	-
24. B.B.#4 (GAS)	155	4,870	4.4	-	-	-	GAS	57,840	1,028,008	59,460.0	251,201	5.16	4.34
25. B.B.#4 (COAL)	422	92,550	30.5	-	-	-	COAL	50,210	22,499,303	1,129,690.0	3,175,693	3.43	63.25
26. BIG BEND #4 TOTAL	422	97,420	32.1	65.5	47.7	12,206	-	-	-	1,189,150.0	3,426,894	3.52	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	7,100	1,026,761	7,290.0	30,835	-	4.34
28. B.B.C.T.#4 TOTAL	56	0	0.0	78.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
29. B.B.C.T.#5 TOTAL	330	32,340	13.6	95.9	100.0	9,428	GAS	296,590	1,027,985	304,890.0	1,288,095	3.98	4.34
30. B.B.C.T.#6 TOTAL	330	7,960	3.4	96.1	56.1	9,922	GAS	76,830	1,027,984	78,980.0	333,674	4.19	4.34
31. BIG BEND STATION TOTAL	1,823	137,720	10.5	67.8	54.9	11,422	-	-	-	1,573,020.0	5,079,498	3.69	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	15,840	10.5	-	80.2	8,912	GAS	137,310	1,028,039	141,160.0	596,340	3.76	4.34
34. POLK #1 TOTAL	220	15,840	10.0	93.8	80.2	8,912	-	-	-	141,160.0	596,340	3.76	-
35. POLK #2 ST DUCT FIRING	120	6,900	8.0	-	62.5	8,280	GAS	55,570	1,028,073	57,130.0	241,341	3.50	4.34
36. POLK #2 ST W/O DUCT FIRING	341	528,880	-	-	-	-	-	3,557,535	1,028,001	3,657,150.0	15,450,435	2.92	4.34
37. POLK #2 ST TOTAL	461	535,780	161.4	-	144.9	6,932	GAS	-	-	3,714,280.0	15,691,776	2.93	-
38. POLK #2 CT (GAS)	150	1,010	0.9	-	96.2	10,822	GAS	10,640	1,027,256	10,930.0	46,210	4.58	4.34
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	45,098	30.07	135.43
40. POLK #2 TOTAL	⁽⁴⁾ 150	1,160	1.1	-	95.9	11,103	-	-	-	12,880.0	91,308	7.87	-
41. POLK #3 CT (GAS)	150	860	0.8	-	95.6	10,756	GAS	8,990	1,028,921	9,250.0	39,044	4.54	4.34
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,963	29.98	135.43
43. POLK #3 TOTAL	⁽⁴⁾ 150	1,010	0.9	-	95.4	11,089	-	-	-	11,200.0	84,007	8.32	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	860	0.8	-	95.6	10,849	GAS	9,070	1,028,666	9,330.0	39,391	4.58	4.34
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	538,810	70.5	97.4	143.7	6,955	-	-	-	3,747,690.0	15,906,482	2.95	-
47. POLK STATION TOTAL	1,281	554,650	60.1	96.8	137.2	7,011	-	-	-	3,888,850.0	16,502,822	2.98	-
48. BAYSIDE #1	720	353,440	68.2	96.6	70.6	7,372	GAS	2,534,590	1,027,997	2,605,550.0	11,007,768	3.11	4.34
49. BAYSIDE #2	954	324,850	47.3	51.9	48.6	7,666	GAS	2,422,490	1,028,000	2,490,320.0	10,520,915	3.24	4.34
50. BAYSIDE #3	56	290	0.7	98.6	86.3	12,103	GAS	3,400	1,032,353	3,510.0	14,766	5.09	4.34
51. BAYSIDE #4	56	170	0.4	78.9	101.2	11,765	GAS	1,950	1,025,641	2,000.0	8,469	4.98	4.34
52. BAYSIDE #5	56	290	0.7	78.9	86.3	11,862	GAS	3,340	1,029,940	3,440.0	14,506	5.00	4.34
53. BAYSIDE #6	56	380	0.9	78.9	84.8	12,053	GAS	4,460	1,026,906	4,580.0	19,370	5.10	4.34
54. BAYSIDE STATION TOTAL	1,898	679,420	49.7	72.6	58.1	7,520	GAS	4,970,230	1,028,001	5,109,400.0	21,585,794	3.18	4.34
55. SYSTEM TOTAL	5,880	1,590,010	37.6	65.6	93.7	6,649	-	-	-	10,571,270.0	43,168,114	2.71	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	340	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	320	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,990	447.1	-	447.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	19,440	37.3	-	37.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	20,230	36.6	-	36.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	20,350	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	16,270	36.0	-	36.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	14,840	36.4	-	36.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	10,020	36.0	-	36.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	12,910	35.1	-	35.1	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	20,170	36.3	-	36.3	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	20,410	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	17,040	38.3	-	38.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	6,940.0	37.5	-	37.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	14,580.0	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	20,700.0	53.2	-	53.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	20,700.0	37.4	-	37.4	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	240,250	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	395	0	0.0	82.1	0.0	0	-	-	-	0.0	0	0.00	-
24. B.B.#4 (GAS)	155	7,190	6.2	-	-	-	GAS	84,220	1,028,022	86,580.0	360,201	5.01	4.28
25. B.B.#4 (COAL)	422	136,640	43.5	-	-	-	COAL	73,110	22,500,205	1,644,990.0	4,571,140	3.35	62.52
26. BIG BEND #4 TOTAL	422	143,830	45.8	89.3	50.0	12,039	-	-	-	1,731,570.0	4,931,341	3.43	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	2,090	1,028,708	2,150.0	8,939	-	4.28
28. B.B.C.T.#4 TOTAL	56	10	0.0	98.3	17.9	31,000	GAS	300	1,033,333	310.0	1,283	12.83	4.28
29. B.B.C.T.#5 TOTAL	330	41,580	16.9	96.9	100.0	9,424	GAS	381,160	1,027,993	391,830.0	1,630,189	3.92	4.28
30. B.B.C.T.#6 TOTAL	330	11,420	4.7	96.1	58.7	9,789	GAS	108,740	1,028,049	111,790.0	465,072	4.07	4.28
31. BIG BEND STATION TOTAL	1,873	196,840	14.1	74.4	56.4	11,357	-	-	-	2,235,500.0	7,036,824	3.57	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	6,550	4.2	-	86.6	8,777	GAS	55,920	1,028,076	57,490.0	239,165	3.65	4.28
34. POLK #1 TOTAL	220	6,550	4.0	72.6	86.6	8,777	-	-	-	57,490.0	239,165	3.65	-
35. POLK #2 ST DUCT FIRING	120	18,460	20.7	-	77.3	8,274	GAS	148,580	1,027,998	152,740.0	635,464	3.44	4.28
36. POLK #2 ST W/O DUCT FIRING	341	600,860	-	-	-	-	-	4,040,365	1,028,001	4,153,500.0	17,280,294	2.88	4.28
37. POLK #2 ST TOTAL	461	619,320	180.6	-	144.0	6,953	GAS	-	-	4,306,240.0	17,915,758	2.89	-
38. POLK #2 CT (GAS)	150	1,350	1.2	-	100.0	10,674	GAS	14,020	1,027,817	14,410.0	59,963	4.44	4.28
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,916	29.94	134.88
40. POLK #2 TOTAL	⁽⁴⁾ 150	1,500	1.3	-	99.4	10,907	-	-	-	16,360.0	104,879	6.99	-
41. POLK #3 CT (GAS)	150	1,200	1.1	-	100.0	10,742	GAS	12,550	1,027,092	12,890.0	53,675	4.47	4.28
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,781	29.85	134.88
43. POLK #3 TOTAL	⁽⁴⁾ 150	1,350	1.2	-	99.3	10,993	-	-	-	14,840.0	98,456	7.29	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	600	0.5	-	100.0	10,767	GAS	6,280	1,028,662	6,460.0	26,859	4.48	4.28
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	622,770	78.9	97.4	142.9	6,975	-	-	-	4,343,900.0	18,145,952	2.91	-
47. POLK STATION TOTAL	1,281	629,320	66.0	93.2	140.9	6,994	-	-	-	4,401,390.0	18,385,117	2.92	-
48. BAYSIDE #1	720	391,490	73.1	96.6	75.5	7,345	GAS	2,797,030	1,028,001	2,875,350.0	11,962,657	3.06	4.28
49. BAYSIDE #2	954	384,720	54.2	97.3	57.7	7,552	GAS	2,826,390	1,028,000	2,905,530.0	12,088,227	3.14	4.28
50. BAYSIDE #3	56	1,310	3.1	98.6	86.6	11,771	GAS	15,000	1,028,000	15,420.0	64,154	4.90	4.28
51. BAYSIDE #4	56	630	1.5	98.6	93.8	11,841	GAS	7,250	1,028,966	7,460.0	31,008	4.92	4.28
52. BAYSIDE #5	56	1,590	3.8	98.6	86.0	11,748	GAS	18,180	1,027,503	18,680.0	77,754	4.89	4.28
53. BAYSIDE #6	56	1,320	3.2	79.5	87.3	11,818	GAS	15,180	1,027,668	15,600.0	64,924	4.92	4.28
54. BAYSIDE STATION TOTAL	1,898	781,060	55.3	96.6	65.6	7,475	GAS	5,679,030	1,027,999	5,838,040.0	24,288,724	3.11	4.28
55. SYSTEM TOTAL	5,930	1,847,470	41.9	74.5	101.2	6,752	-	-	-	12,474,930.0	49,710,665	2.69	-

LEGEND:

B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition

⁽²⁾ Fuel burned (MM BTU) system total excludes ignition

⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	290	2.1	-	2.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,420	409.3	-	409.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,790	33.3	-	33.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	17,430	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,440	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	14,020	32.0	-	32.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,800	32.4	-	32.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,680	32.2	-	32.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	11,120	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,570	30.8	-	30.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,510	32.7	-	32.7	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,740	34.2	-	34.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	5,950.0	33.2	-	33.2	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	12,500.0	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	17,740.0	47.1	-	47.1	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	17,740.0	33.2	-	33.2	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	206,030	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	51,360	20.7	-	-	-	GAS	582,810	1,027,985	599,120.0	2,429,064	4.73	4.17
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	51,360	20.7	82.1	60.0	11,665	-	-	-	599,120.0	2,429,064	4.73	-
24. B.B.#4 (GAS)	155	7,620	6.8	-	-	-	GAS	87,040	1,027,918	89,470.0	362,770	4.76	4.17
25. B.B.#4 (COAL)	422	144,780	47.7	-	-	-	COAL	75,560	22,498,677	1,700,000.0	4,730,807	3.27	62.61
26. BIG BEND #4 TOTAL	422	152,400	50.2	89.3	54.7	11,742	-	-	-	1,789,470.0	5,093,577	3.34	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	21,290	1,028,182	21,890.0	88,734	-	4.17
28. B.B.C.T.#4 TOTAL	56	2,150	5.3	98.3	85.3	11,795	GAS	24,660	1,028,386	25,360.0	102,779	4.78	4.17
29. B.B.C.T.#5 TOTAL	330	52,070	21.9	96.9	22.3	11,751	GAS	595,240	1,027,989	611,900.0	2,480,871	4.76	4.17
30. B.B.C.T.#6 TOTAL	330	12,960	5.5	96.1	5.6	19,951	GAS	251,520	1,027,990	258,560.0	1,048,298	8.09	4.17
31. BIG BEND STATION TOTAL	1,823	270,940	20.6	74.1	32.5	12,122	-	-	-	3,284,410.0	11,243,323	4.15	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	59,650	39.5	-	87.1	8,781	GAS	509,530	1,028,006	523,800.0	2,123,645	3.56	4.17
34. POLK #1 TOTAL	220	59,650	37.7	93.8	87.1	8,781	-	-	-	523,800.0	2,123,645	3.56	-
35. POLK #2 ST DUCT FIRING	120	27,910	32.3	-	92.3	8,275	GAS	224,670	1,027,997	230,960.0	936,391	3.36	4.17
36. POLK #2 ST W/O DUCT FIRING	341	594,750	-	-	-	-	-	3,998,515	1,028,004	4,110,490.0	16,665,211	2.80	4.17
37. POLK #2 ST TOTAL	461	622,660	187.6	-	141.0	6,972	GAS	-	-	4,341,450.0	17,601,602	2.83	-
38. POLK #2 CT (GAS)	150	300	0.3	-	100.0	10,733	GAS	3,130	1,028,754	3,220.0	13,044	4.35	4.17
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,733	29.82	134.33
40. POLK #2 TOTAL	⁽⁴⁾ 150	450	0.4	-	98.0	11,489	-	-	-	5,170.0	57,777	12.84	-
41. POLK #3 CT (GAS)	150	300	0.3	-	100.0	11,000	GAS	3,210	1,028,037	3,300.0	13,379	4.46	4.17
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,599	29.73	134.33
43. POLK #3 TOTAL	⁽⁴⁾ 150	450	0.4	-	98.0	11,667	-	-	-	5,250.0	57,978	12.88	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	300	0.3	-	100.0	11,000	GAS	3,210	1,028,037	3,300.0	13,379	4.46	4.17
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	623,860	81.7	97.4	140.6	6,981	-	-	-	4,355,170.0	17,730,736	2.84	-
47. POLK STATION TOTAL	1,281	683,510	74.1	96.8	127.1	7,138	-	-	-	4,878,970.0	19,854,381	2.90	-
48. BAYSIDE #1	720	396,130	76.4	96.6	79.0	7,325	GAS	2,822,700	1,027,998	2,901,730.0	11,764,590	2.97	4.17
49. BAYSIDE #2	954	416,000	60.6	97.3	63.0	7,501	GAS	3,035,300	1,027,997	3,120,280.0	12,650,675	3.04	4.17
50. BAYSIDE #3	56	5,410	13.4	98.6	89.5	11,603	GAS	61,050	1,028,174	62,770.0	254,447	4.70	4.17
51. BAYSIDE #4	56	4,370	10.8	98.6	89.7	11,643	GAS	49,500	1,027,879	50,880.0	206,309	4.72	4.17
52. BAYSIDE #5	56	6,820	16.9	98.6	85.8	11,729	GAS	77,810	1,028,017	79,990.0	324,300	4.76	4.17
53. BAYSIDE #6	56	5,410	13.4	98.6	86.3	11,713	GAS	61,640	1,028,066	63,370.0	256,906	4.75	4.17
54. BAYSIDE STATION TOTAL	1,898	834,140	61.0	97.2	70.3	7,528	GAS	6,108,000	1,027,999	6,279,020.0	25,457,227	3.05	4.17
55. SYSTEM TOTAL	5,880	1,994,620	47.1	75.4	84.4	7,241	-	-	-	14,442,400.0	56,554,931	2.84	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	290	2.0	-	2.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,270	382.6	-	382.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,270	31.2	-	31.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,880	30.6	-	30.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,240	31.2	-	31.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,590	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,410	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,460	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,760	29.3	-	29.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	16,330	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,300	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,280	32.1	-	32.1	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	5,770.0	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	12,110.0	21.9	-	21.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	17,190.0	44.2	-	44.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	17,190.0	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	200,630	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	50,200	19.6	-	-	-	GAS	580,440	1,027,996	596,690.0	2,432,654	4.85	4.19
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	50,200	19.6	82.1	55.1	11,886	-	-	-	596,690.0	2,432,654	4.85	-
24. B.B.#4 (GAS)	155	8,120	7.0	-	-	-	GAS	92,030	1,028,034	94,610.0	385,702	4.75	4.19
25. B.B.#4 (COAL)	422	154,270	49.1	-	-	-	COAL	79,890	22,499,812	1,797,510.0	5,010,894	3.25	62.72
26. BIG BEND #4 TOTAL	422	162,390	51.7	89.3	56.4	11,652	-	-	-	1,892,120.0	5,396,596	3.32	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	16,280	1,028,256	16,740.0	68,230	-	4.19
28. B.B.C.T.#4 TOTAL	56	2,830	6.8	98.3	76.6	12,155	GAS	33,460	1,028,093	34,400.0	140,233	4.96	4.19
29. B.B.C.T.#5 TOTAL	330	57,960	23.6	96.9	24.1	9,101	GAS	513,150	1,028,004	527,520.0	2,150,637	3.71	4.19
30. B.B.C.T.#6 TOTAL	330	0	0.0	96.1	0.0	0	GAS	80	1,000,000	80.0	335	0.00	4.19
31. BIG BEND STATION TOTAL	1,823	273,380	20.2	74.1	31.6	11,160	-	-	-	3,050,810.0	10,188,685	3.73	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	55,670	35.6	-	87.2	8,779	GAS	475,380	1,028,020	488,700.0	1,992,341	3.58	4.19
34. POLK #1 TOTAL	220	55,670	34.0	93.8	87.2	8,779	-	-	-	488,700.0	1,992,341	3.58	-
35. POLK #2 ST DUCT FIRING	120	28,680	32.1	-	90.5	8,275	GAS	230,850	1,028,027	237,320.0	967,504	3.37	4.19
36. POLK #2 ST W/O DUCT FIRING	341	617,480	-	-	-	-	-	4,151,525	1,028,001	4,267,770.0	17,399,249	2.82	4.19
37. POLK #2 ST TOTAL	461	646,160	188.4	-	140.4	6,972	GAS	-	-	4,505,090.0	18,366,753	2.84	-
38. POLK #2 CT (GAS)	150	1,500	1.3	-	100.0	10,700	GAS	15,620	1,027,529	16,050.0	65,464	4.36	4.19
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,553	29.70	133.79
40. POLK #2 TOTAL	⁽⁴⁾ 150	1,650	1.5	-	99.5	10,909	-	-	-	18,000.0	110,017	6.67	-
41. POLK #3 CT (GAS)	150	1,050	0.9	-	100.0	10,686	GAS	10,910	1,028,414	11,220.0	45,724	4.35	4.19
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,420	29.61	133.80
43. POLK #3 TOTAL	⁽⁴⁾ 150	1,200	1.1	-	99.3	10,975	-	-	-	13,170.0	90,144	7.51	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	1,350	1.2	-	100.0	10,733	GAS	14,100	1,027,660	14,490.0	59,094	4.38	4.19
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	1,200	1.1	-	100.0	10,742	GAS	12,550	1,027,092	12,890.0	52,598	4.38	4.19
46. POLK #2 CC TOTAL	1,061	651,560	82.5	97.4	139.0	7,004	-	-	-	4,563,640.0	18,678,606	2.87	-
47. POLK STATION TOTAL	1,281	707,230	74.2	96.8	127.3	7,144	-	-	-	5,052,340.0	20,670,947	2.92	-
48. BAYSIDE #1	720	416,240	77.7	96.6	80.3	7,318	GAS	2,963,250	1,028,000	3,046,220.0	12,419,129	2.98	4.19
49. BAYSIDE #2	954	452,840	63.8	97.3	65.7	7,476	GAS	3,293,140	1,028,001	3,385,350.0	13,801,715	3.05	4.19
50. BAYSIDE #3	56	5,710	13.7	98.6	84.3	11,764	GAS	65,330	1,028,165	67,170.0	273,801	4.80	4.19
51. BAYSIDE #4	56	4,890	11.7	98.6	85.6	11,722	GAS	55,780	1,027,608	57,320.0	233,777	4.78	4.19
52. BAYSIDE #5	56	7,050	16.9	98.6	86.2	11,672	GAS	80,060	1,027,854	82,290.0	335,535	4.76	4.19
53. BAYSIDE #6	56	6,420	15.4	98.6	84.3	11,746	GAS	73,360	1,027,944	75,410.0	307,455	4.79	4.19
54. BAYSIDE STATION TOTAL	1,898	893,150	63.2	97.2	72.2	7,517	GAS	6,530,920	1,027,996	6,713,760.0	27,371,412	3.06	4.19
55. SYSTEM TOTAL	5,880	2,074,390	47.4	75.4	84.5	7,143	-	-	-	14,816,910.0	58,231,044	2.81	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	270	1.9	-	1.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,180	374.6	-	374.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	15,700	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,280	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	16,650	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,120	29.0	-	29.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	11,990	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,320	29.9	-	29.9	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,390	28.3	-	28.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	15,830	28.5	-	28.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	16,730	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	13,780	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	5,560.0	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	11,680.0	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	16,570.0	42.6	-	42.6	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	16,570.0	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	193,910	29.7	-	29.7	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	1,055	3,320	0.4	0.0	13.1	7,461	GAS	24,090	1,028,227	24,770.0	99,941	3.01	4.15
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	43,110	16.8	-	-	-	GAS	490,850	1,028,013	504,600.0	2,036,365	4.72	4.15
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	43,110	16.8	82.1	58.9	11,705	-	-	-	504,600.0	2,036,365	4.72	-
24. B.B.#4 (GAS)	155	8,360	7.2	-	-	-	GAS	94,000	1,027,979	96,630.0	389,973	4.66	4.15
25. B.B.#4 (COAL)	422	158,760	50.6	-	-	-	COAL	81,600	22,500,368	1,836,030.0	5,123,910	3.23	62.79
26. BIG BEND #4 TOTAL	422	167,120	53.2	89.3	58.1	11,565	-	-	-	1,932,660.0	5,513,883	3.30	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	17,120	1,028,037	17,600.0	71,025	-	4.15
28. B.B.C.T.#4 TOTAL	56	2,870	6.9	98.3	81.3	11,969	GAS	33,420	1,027,828	34,350.0	138,648	4.83	4.15
29. B.B.C.T.#5 TOTAL	330	63,010	25.7	96.9	29.0	9,100	GAS	557,770	1,027,986	573,380.0	2,313,992	3.67	4.15
30. B.B.C.T.#6 TOTAL	330	120,960	49.3	96.1	55.6	9,101	GAS	1,070,830	1,028,006	1,100,820.0	4,442,499	3.67	4.15
31. BIG BEND STATION TOTAL	2,878	400,390	18.7	47.0	48.5	10,416	-	-	-	4,170,580.0	14,616,353	3.65	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	53,040	33.9	-	84.2	8,838	GAS	456,010	1,027,982	468,770.0	1,891,826	3.57	4.15
34. POLK #1 TOTAL	220	53,040	32.4	93.8	84.2	8,838	-	-	-	468,770.0	1,891,826	3.57	-
35. POLK #2 ST DUCT FIRING	120	21,660	24.3	-	91.6	8,277	GAS	174,410	1,027,980	179,290.0	723,566	3.34	4.15
36. POLK #2 ST W/O DUCT FIRING	341	618,070	-	-	-	-	-	4,155,105	1,028,000	4,271,450.0	17,238,076	2.79	4.15
37. POLK #2 ST TOTAL	461	639,730	186.5	-	149.1	6,957	GAS	-	-	4,450,740.0	17,961,642	2.81	-
38. POLK #2 CT (GAS)	150	1,500	1.3	-	100.0	10,727	GAS	15,660	1,027,458	16,090.0	64,967	4.33	4.15
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,375	29.58	133.26
40. POLK #2 TOTAL	⁽⁴⁾ 150	1,650	1.5	-	99.5	10,933	-	-	-	18,040.0	109,342	6.63	-
41. POLK #3 CT (GAS)	150	1,350	1.2	-	100.0	10,733	GAS	14,100	1,027,660	14,490.0	58,496	4.33	4.15
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,243	29.50	133.26
43. POLK #3 TOTAL	⁽⁴⁾ 150	1,500	1.3	-	99.4	10,960	-	-	-	16,440.0	102,739	6.85	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	1,350	1.2	-	100.0	10,733	GAS	14,100	1,027,660	14,490.0	58,496	4.33	4.15
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	1,200	1.1	-	100.0	10,675	GAS	12,470	1,027,265	12,810.0	51,734	4.31	4.15
46. POLK #2 CC TOTAL	1,061	645,430	81.8	97.4	147.1	6,991	-	-	-	4,512,520.0	18,283,953	2.83	-
47. POLK STATION TOTAL	1,281	698,470	73.3	96.8	132.2	7,132	-	-	-	4,981,290.0	20,175,779	2.89	-
48. BAYSIDE #1	720	387,880	72.4	96.6	78.6	7,327	GAS	2,764,590	1,027,997	2,841,990.0	11,469,316	2.96	4.15
49. BAYSIDE #2	954	418,950	59.0	97.3	61.1	7,521	GAS	3,064,920	1,027,997	3,150,730.0	12,715,280	3.04	4.15
50. BAYSIDE #3	56	3,810	9.1	98.6	81.0	11,953	GAS	44,290	1,028,223	45,540.0	183,744	4.82	4.15
51. BAYSIDE #4	56	3,250	7.8	98.6	80.6	12,049	GAS	38,090	1,028,091	39,160.0	158,022	4.86	4.15
52. BAYSIDE #5	56	4,590	11.0	98.6	76.6	12,142	GAS	54,210	1,028,039	55,730.0	224,898	4.90	4.15
53. BAYSIDE #6	56	4,320	10.4	98.6	79.5	12,009	GAS	50,470	1,027,937	51,880.0	209,382	4.85	4.15
54. BAYSIDE STATION TOTAL	1,898	822,800	58.3	97.2	68.6	7,517	GAS	6,016,570	1,027,999	6,185,030.0	24,960,642	3.03	4.15
55. SYSTEM TOTAL	6,935	2,115,570	41.0	64.0	89.3	7,250	-	-	-	15,336,900.0	59,752,774	2.82	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	230	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,470	321.3	-	321.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,650	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,140	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,340	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,390	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,420	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,720	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	9,030	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	13,680	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,370	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,990	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,830.0	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	10,150.0	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	14,400.0	38.2	-	38.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,400.0	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	167,470	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	1,055	296,610	39.0	0.0	40.0	6,291	GAS	1,815,250	1,028,007	1,866,090.0	7,578,296	2.55	4.17
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	48,640	19.6	-	-	-	GAS	549,750	1,027,995	565,140.0	2,295,094	4.72	4.17
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	48,640	19.6	82.1	61.0	11,619	-	-	-	565,140.0	2,295,094	4.72	-
24. B.B.#4 (GAS)	155	8,130	7.3	-	-	-	GAS	91,280	1,027,936	93,830.0	381,075	4.69	4.17
25. B.B.#4 (COAL)	422	154,310	50.8	-	-	-	COAL	79,240	22,499,243	1,782,840.0	4,979,203	3.23	62.84
26. BIG BEND #4 TOTAL	422	162,440	53.5	89.3	58.3	11,553	-	-	-	1,876,670.0	5,360,278	3.30	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	21,300	1,027,700	21,890.0	88,923	-	4.17
28. B.B.C.T.#4 TOTAL	56	8,700	21.6	98.3	86.3	11,622	GAS	98,350	1,028,063	101,110.0	410,591	4.72	4.17
29. B.B.C.T.#5 TOTAL	330	0	0.0	96.9	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. B.B.C.T.#6 TOTAL	330	0	0.0	96.1	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BIG BEND STATION TOTAL	2,878	516,390	24.9	47.0	46.5	8,538	-	-	-	4,409,010.0	15,733,182	3.05	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	54,730	36.2	-	90.8	8,696	GAS	462,980	1,027,993	475,940.0	1,932,846	3.53	4.17
34. POLK #1 TOTAL	220	54,730	34.6	93.8	90.8	8,696	-	-	-	475,940.0	1,932,846	3.53	-
35. POLK #2 ST DUCT FIRING	120	31,280	36.2	-	89.3	8,276	GAS	251,810	1,027,997	258,860.0	1,051,255	3.36	4.17
36. POLK #2 ST W/O DUCT FIRING	341	573,230	-	-	-	-	-	3,857,255	1,028,003	3,965,270.0	16,103,247	2.81	4.17
37. POLK #2 ST TOTAL	461	604,510	182.1	-	130.9	6,988	GAS	-	-	4,224,130.0	17,154,502	2.84	-
38. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	1	0.00	0.00
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,200	29.47	132.73
40. POLK #2 TOTAL	⁽⁴⁾ 150	150	0.1	-	94.3	13,000	-	-	-	1,950.0	44,201	29.47	-
41. POLK #3 CT (GAS)	150	1,200	1.1	-	100.0	10,708	GAS	12,500	1,028,000	12,850.0	52,185	4.35	4.17
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,067	29.38	132.73
43. POLK #3 TOTAL	⁽⁴⁾ 150	1,350	1.3	-	99.3	10,963	-	-	-	14,800.0	96,252	7.13	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	1,040	1.0	-	99.0	10,817	GAS	10,950	1,027,397	11,250.0	45,714	4.40	4.17
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	900	0.8	-	100.0	10,722	GAS	9,390	1,027,689	9,650.0	39,201	4.36	4.17
46. POLK #2 CC TOTAL	1,061	607,950	79.6	97.4	130.2	7,010	-	-	-	4,261,780.0	17,379,870	2.86	-
47. POLK STATION TOTAL	1,281	662,680	71.8	96.8	121.6	7,149	-	-	-	4,737,720.0	19,312,716	2.91	-
48. BAYSIDE #1	720	101,560	19.6	29.0	67.5	7,400	GAS	731,050	1,028,014	751,530.0	3,051,984	3.01	4.17
49. BAYSIDE #2	954	440,590	64.1	97.3	66.0	7,482	GAS	3,206,840	1,027,996	3,296,620.0	13,387,898	3.04	4.17
50. BAYSIDE #3	56	8,860	22.0	98.6	87.4	11,620	GAS	100,130	1,028,163	102,950.0	418,022	4.72	4.17
51. BAYSIDE #4	56	8,920	22.1	98.6	88.5	11,557	GAS	100,280	1,028,022	103,090.0	418,648	4.69	4.17
52. BAYSIDE #5	56	9,650	23.9	98.6	85.3	11,662	GAS	109,470	1,028,044	112,540.0	457,015	4.74	4.17
53. BAYSIDE #6	56	10,030	24.9	98.6	87.4	11,587	GAS	113,050	1,028,041	116,220.0	471,961	4.71	4.17
54. BAYSIDE STATION TOTAL	1,898	579,610	42.4	71.5	67.3	7,734	GAS	4,360,820	1,028,006	4,482,950.0	18,205,528	3.14	4.17
55. SYSTEM TOTAL	6,935	1,926,150	38.6	56.9	83.2	7,076	-	-	-	13,629,680.0	53,251,426	2.76	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	220	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,590	321.7	-	321.7	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,490	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,990	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,980	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,250	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,300	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	7,100	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,930	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	14,210	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,040	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,850	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,790.0	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	10,070.0	18.2	-	18.2	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	14,280.0	36.7	-	36.7	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,280.0	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	166,660	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	1,055	664,980	84.7	0.0	86.8	6,234	GAS	4,032,710	1,028,004	4,145,640.0	16,927,062	2.55	4.20
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	44,880	17.5	-	-	-	GAS	510,250	1,028,025	524,550.0	2,141,744	4.77	4.20
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	44,880	17.5	82.1	59.4	11,688	-	-	-	524,550.0	2,141,744	4.77	-
24. B.B.#4 (GAS)	155	830	0.7	-	-	-	GAS	9,320	1,027,897	9,580.0	39,120	4.71	4.20
25. B.B.#4 (COAL)	422	15,880	5.1	-	-	-	COAL	8,090	22,508,035	182,090.0	509,008	3.21	62.92
26. BIG BEND #4 TOTAL	422	16,710	5.3	8.6	60.0	11,470	-	-	-	191,670.0	548,128	3.28	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	12,110	1,028,076	12,450.0	50,831	-	4.20
28. B.B.C.T.#4 TOTAL	56	2,180	5.2	98.3	76.3	12,197	GAS	25,880	1,027,434	26,590.0	108,630	4.98	4.20
29. B.B.C.T.#5 TOTAL	330	0	0.0	96.9	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. B.B.C.T.#6 TOTAL	330	0	0.0	96.1	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BIG BEND STATION TOTAL	2,878	728,750	34.0	35.1	83.6	6,708	-	-	-	4,888,450.0	19,776,395	2.71	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	47,070	30.1	-	83.0	8,883	GAS	406,740	1,028,003	418,130.0	1,707,267	3.63	4.20
34. POLK #1 TOTAL	220	47,070	28.8	93.8	83.0	8,883	-	-	-	418,130.0	1,707,267	3.63	-
35. POLK #2 ST DUCT FIRING	120	17,210	19.3	-	81.5	8,276	GAS	138,550	1,028,004	142,430.0	581,555	3.38	4.20
36. POLK #2 ST W/O DUCT FIRING	341	523,710	-	-	-	-	-	3,534,145	1,028,003	3,633,110.0	14,834,364	2.83	4.20
37. POLK #2 ST TOTAL	461	540,920	157.7	-	129.1	6,980	GAS	-	-	3,775,540.0	15,415,919	2.85	-
38. POLK #2 CT (GAS)	150	410	0.4	-	68.3	12,293	GAS	4,910	1,026,477	5,040.0	20,610	5.03	4.20
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,027	29.35	132.21
40. POLK #2 TOTAL	⁽⁴⁾ 150	560	0.5	-	73.8	12,482	-	-	-	6,990.0	64,637	11.54	-
41. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	43,895	29.26	132.21
43. POLK #3 TOTAL	⁽⁴⁾ 150	150	0.1	-	94.3	13,000	-	-	-	1,950.0	43,895	29.26	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	541,630	68.6	97.4	128.7	6,987	-	-	-	3,784,480.0	15,524,451	2.87	-
47. POLK STATION TOTAL	1,281	588,700	61.8	96.8	118.3	7,139	-	-	-	4,202,610.0	17,231,718	2.93	-
48. BAYSIDE #1	720	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
49. BAYSIDE #2	954	318,550	44.9	97.3	46.4	7,709	GAS	2,388,740	1,027,994	2,455,610.0	10,026,594	3.15	4.20
50. BAYSIDE #3	56	3,580	8.6	98.6	79.9	12,006	GAS	41,830	1,027,492	42,980.0	175,579	4.90	4.20
51. BAYSIDE #4	56	3,100	7.4	98.6	81.4	11,965	GAS	36,080	1,027,993	37,090.0	151,444	4.89	4.20
52. BAYSIDE #5	56	4,890	11.7	98.6	76.6	12,125	GAS	57,680	1,027,913	59,290.0	242,108	4.95	4.20
53. BAYSIDE #6	56	3,600	8.6	98.6	78.4	12,106	GAS	42,390	1,028,073	43,580.0	177,930	4.94	4.20
54. BAYSIDE STATION TOTAL	1,898	333,720	23.6	60.5	47.3	7,906	GAS	2,566,720	1,027,985	2,638,550.0	10,773,655	3.23	4.20
55. SYSTEM TOTAL	6,935	1,817,830	35.2	49.0	95.2	6,453	-	-	-	11,729,610.0	47,781,768	2.63	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	180	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,960	273.7	-	273.7	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	10,090	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,450	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	11,980	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,390	19.1	-	19.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,680	19.4	-	19.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,010	22.3	-	22.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,670	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,740	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,030	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,860	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,590.0	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	7,530.0	14.1	-	14.1	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	10,690.0	28.3	-	28.3	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	10,690.0	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	129,810	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	1,055	758,410	99.7	0.0	102.3	6,229	GAS	4,595,280	1,028,000	4,723,950.0	20,323,688	2.68	4.42
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	9,030	3.6	-	-	-	GAS	104,650	1,027,998	107,580.0	462,839	5.13	4.42
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	9,030	3.6	43.8	54.5	11,914	-	-	-	107,580.0	462,839	5.13	-
24. B.B.#4 (GAS)	155	6,000	5.4	-	-	-	GAS	71,970	1,027,928	73,980.0	318,304	5.31	4.42
25. B.B.#4 (COAL)	422	114,030	37.5	-	-	-	COAL	62,470	22,501,361	1,405,660.0	3,930,668	3.45	62.92
26. BIG BEND #4 TOTAL	422	120,030	39.4	83.3	46.2	12,327	-	-	-	1,479,640.0	4,248,972	3.54	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	12,110	1,027,250	12,440.0	53,559	-	4.42
28. B.B.C.T.#4 TOTAL	56	110	0.3	98.3	65.5	13,091	GAS	1,400	1,028,571	1,440.0	6,192	5.63	4.42
29. B.B.C.T.#5 TOTAL	330	0	0.0	96.9	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. B.B.C.T.#6 TOTAL	330	0	0.0	96.1	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BIG BEND STATION TOTAL	2,878	887,580	42.8	41.5	87.2	7,112	-	-	-	6,312,610.0	25,095,250	2.83	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	7,830	5.2	-	79.3	8,921	GAS	67,950	1,027,962	69,850.0	300,525	3.84	4.42
34. POLK #1 TOTAL	220	7,830	4.9	93.8	79.3	8,921	-	-	-	69,850.0	300,525	3.84	-
35. POLK #2 ST DUCT FIRING	120	1,580	1.8	-	59.8	8,247	GAS	12,680	1,027,603	13,030.0	56,080	3.55	4.42
36. POLK #2 ST W/O DUCT FIRING	341	302,000	-	-	-	-	-	2,079,175	1,028,004	2,137,400.0	9,195,632	3.04	4.42
37. POLK #2 ST TOTAL	461	303,580	91.3	-	90.1	7,084	GAS	-	-	2,150,430.0	9,251,712	3.05	-
38. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	43,857	29.24	131.70
40. POLK #2 TOTAL	⁽⁴⁾ 150	150	0.1	-	94.3	13,000	-	-	-	1,950.0	43,857	29.24	-
41. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	43,725	29.15	131.70
43. POLK #3 TOTAL	⁽⁴⁾ 150	150	0.1	-	94.3	13,000	-	-	-	1,950.0	43,725	29.15	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL ⁽⁴⁾	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL ⁽⁴⁾	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	303,880	39.7	97.4	90.1	7,089	-	-	-	2,154,330.0	9,339,294	3.07	-
47. POLK STATION TOTAL	1,281	311,710	33.7	96.8	89.4	7,135	-	-	-	2,224,180.0	9,639,819	3.09	-
48. BAYSIDE #1	720	15,230	2.9	25.8	32.0	7,957	GAS	117,880	1,027,995	121,180.0	521,351	3.42	4.42
49. BAYSIDE #2	954	131,950	19.2	97.3	26.8	8,308	GAS	1,066,370	1,028,020	1,096,250.0	4,716,268	3.57	4.42
50. BAYSIDE #3	56	120	0.3	98.6	71.4	12,917	GAS	1,510	1,026,490	1,550.0	6,678	5.57	4.42
51. BAYSIDE #4	56	60	0.1	98.6	53.6	14,833	GAS	870	1,022,989	890.0	3,848	6.41	4.42
52. BAYSIDE #5	56	140	0.3	98.6	62.5	14,071	GAS	1,920	1,026,042	1,970.0	8,492	6.07	4.42
53. BAYSIDE #6	56	120	0.3	98.6	53.6	14,500	GAS	1,690	1,029,586	1,740.0	7,474	6.23	4.42
54. BAYSIDE STATION TOTAL	1,898	147,620	10.8	70.3	27.3	8,289	GAS	1,190,240	1,028,011	1,223,580.0	5,264,111	3.57	4.42
55. SYSTEM TOTAL	6,935	1,476,720	29.5	54.3	81.4	6,609	-	-	-	9,760,370.0	39,999,180	2.71	-

LEGEND:

B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition

⁽²⁾ Fuel burned (MM BTU) system total excludes ignition

⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	160	1.1	-	1.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,680	240.1	-	240.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	8,470	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	8,770	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	10,360	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	7,030	15.5	-	15.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	6,450	15.8	-	15.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,030	18.1	-	18.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	5,600	15.2	-	15.2	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	10,430	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	10,410	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	7,440	16.7	-	16.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,010	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	6,320	11.4	-	11.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	8,970	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	8,970	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	22.2	7,860	47.6	-	47.6	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	65.0	8,080	16.7	-	16.7	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	2,680	5.1	-	5.1	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	66.8	8,460	17.0	-	17.0	-	SOLAR	-	-	-	-	-	-
22. SOLAR TOTAL	⁽³⁾ 1102.0	137,440	16.8	-	16.8	-	SOLAR	-	-	-	-	-	-
23. BIG BEND #1 CC TOTAL	1,120	787,780	94.5	98.0	96.9	6,277	GAS	4,810,060	1,028,002	4,944,750.0	21,872,120	2.78	4.55
24. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
25. B.B.#3 (GAS)	355	13,470	5.1	-	-	-	GAS	155,030	1,028,059	159,380.0	704,947	5.23	4.55
26. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
27. BIG BEND #3 TOTAL	355	13,470	5.1	82.1	52.7	11,832	-	-	-	159,380.0	704,947	5.23	-
28. B.B.#4 (GAS)	160	6,890	5.8	-	-	-	GAS	80,970	1,028,035	83,240.0	368,184	5.34	4.55
29. B.B.#4 (COAL)	432	130,860	40.7	-	-	-	COAL	70,290	22,500,925	1,581,590.0	4,423,948	3.38	62.94
30. BIG BEND #4 TOTAL	432	137,750	42.9	89.3	46.8	12,086	-	-	-	1,664,830.0	4,792,132	3.48	-
31. B.B. IGNITION	-	-	-	-	-	-	GAS	6,260	1,028,754	6,440.0	28,465	-	4.55
32. B.B.C.T.#4 TOTAL	61	430	0.9	98.3	88.1	11,628	GAS	4,880	1,024,590	5,000.0	22,190	5.16	4.55
33. B.B.C.T.#5 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. B.B.C.T.#6 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. BIG BEND STATION TOTAL	3,018	939,430	41.8	60.8	82.9	7,211	-	-	-	6,773,960.0	27,419,854	2.92	-
36. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
37. POLK #1 CT (GAS)	230	21,630	12.6	-	73.5	8,961	GAS	188,540	1,028,058	193,830.0	857,322	3.96	4.55
38. POLK #1 TOTAL	230	21,630	12.6	93.8	73.5	8,961	-	-	-	193,830.0	857,322	3.96	-
39. POLK #2 ST DUCT FIRING	120	2,310	2.6	-	83.7	8,182	GAS	18,380	1,028,292	18,900.0	83,577	3.62	4.55
40. POLK #2 ST W/O DUCT FIRING	360	239,370	-	-	-	-	-	1,659,095	1,028,006	1,705,560.0	7,544,173	3.15	4.55
41. POLK #2 ST TOTAL	480	241,680	67.7	-	80.6	7,135	GAS	-	-	1,724,460.0	7,627,750	3.16	-
42. POLK #2 CT (GAS)	180	1,580	1.2	-	67.5	11,652	GAS	17,900	1,028,492	18,410.0	81,393	5.15	4.55
43. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	43,688	29.13	131.20
44. POLK #2 TOTAL	⁽⁴⁾ 180	1,730	1.3	-	68.5	11,769	-	-	-	20,360.0	125,081	7.23	-
45. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	43,558	29.04	131.20
47. POLK #3 TOTAL	⁽⁴⁾ 180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	43,558	29.04	-

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
48. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 180	940	0.7	-	65.3	11,681	GAS	10,680	1,028,090	10,980.0	48,564	5.17	4.55
49. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 180	930	0.7	-	64.6	11,806	GAS	10,680	1,028,090	10,980.0	48,564	5.22	4.55
50. POLK #2 CC TOTAL	1,200	245,430	27.5	81.7	79.9	7,207	-	-	-	1,768,730.0	7,893,517	3.22	-
51. POLK STATION TOTAL	1,430	267,060	25.1	83.7	78.9	7,349	-	-	-	1,962,560.0	8,750,839	3.28	-
52. BAYSIDE #1	792	137,370	23.3	96.6	32.7	7,702	GAS	1,029,200	1,028,002	1,058,020.0	4,679,939	3.41	4.55
53. BAYSIDE #2	1,047	51,050	6.6	97.3	28.3	8,042	GAS	399,370	1,027,994	410,550.0	1,815,999	3.56	4.55
54. BAYSIDE #3	61	380	0.8	98.6	89.0	11,342	GAS	4,190	1,028,640	4,310.0	19,053	5.01	4.55
55. BAYSIDE #4	61	330	0.7	98.6	90.2	11,485	GAS	3,690	1,027,100	3,790.0	16,779	5.08	4.55
56. BAYSIDE #5	61	470	1.0	98.6	85.6	11,723	GAS	5,360	1,027,985	5,510.0	24,373	5.19	4.55
57. BAYSIDE #6	61	420	0.9	98.6	86.1	11,762	GAS	4,810	1,027,027	4,940.0	21,872	5.21	4.55
58. BAYSIDE STATION TOTAL	2,083	190,020	12.3	97.2	31.5	7,826	GAS	1,446,620	1,027,996	1,487,120.0	6,578,015	3.46	4.55
59. SYSTEM TOTAL	7,633	1,533,950	27.0	66.2	77.1	6,665	-	-	-	10,223,640.0	42,748,708	2.79	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating

⁽⁴⁾ In Simple Cycle Mode

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH JUNE 2022

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT (\$)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT (\$)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT (\$)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	665	665	665	665	665	665
16. UNIT COST (\$/BBL)	102.65	102.38	101.85	101.07	100.43	99.96
17. AMOUNT (\$)	68,265	68,083	67,728	67,209	66,788	66,475
18. BURNED:						
19. UNITS (BBL)	665	665	665	665	665	665
20. UNIT COST (\$/BBL)	137.07	136.52	135.98	135.43	134.88	134.33
21. AMOUNT (\$)	91,149	90,787	90,425	90,061	89,697	89,332
22. ENDING INVENTORY:						
23. UNITS (BBL)	41,760	41,760	41,760	41,760	41,760	41,760
24. UNIT COST (\$/BBL)	137.03	136.49	135.94	135.40	134.85	134.30
25. AMOUNT (\$)	5,722,460	5,699,756	5,677,059	5,654,207	5,631,298	5,608,440
26. DAYS SUPPLY: NORMAL	1,909,609	1,909,599	1,909,599	1,909,599	1,909,599	1,909,599
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	65,000	55,000	70,000	70,000	55,000	45,000
30. UNIT COST (\$/TON)	64.46	63.99	63.38	63.47	64.03	61.43
31. AMOUNT (\$)	4,190,125	3,519,461	4,436,677	4,442,855	3,521,454	2,764,201
32. BURNED:						
33. UNITS (TONS)	72,550	63,500	57,140	50,210	73,110	75,560
34. UNIT COST (\$/TON)	62.11	62.83	62.33	63.25	62.52	62.61
35. AMOUNT (\$)	4,505,889	3,989,914	3,561,514	3,175,693	4,571,140	4,730,807
36. ENDING INVENTORY:						
37. UNITS (TONS)	232,888	224,388	237,248	257,038	238,928	208,368
38. UNIT COST (\$/TON)	60.96	61.42	61.84	62.22	62.62	62.46
39. AMOUNT (\$)	14,196,096	13,782,069	14,672,013	15,992,163	14,961,389	13,014,329
40. DAYS SUPPLY:	108	117	121	118	96	81
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	8,871,536	7,779,965	8,734,935	9,187,705	10,533,255	12,412,825
43. UNIT COST (\$/MCF)	5.19	5.09	4.80	4.32	4.27	4.17
44. AMOUNT (\$)	46,057,217	39,598,109	41,955,637	39,702,520	45,016,467	51,745,193
45. BURNED:						
46. UNITS (MCF)	8,871,535	7,779,965	8,734,935	9,187,705	10,533,255	12,412,825
47. UNIT COST (\$/MCF)	5.19	5.09	4.81	4.34	4.28	4.17
48. AMOUNT (\$)	46,031,617	39,631,629	42,052,837	39,902,360	45,049,828	51,734,792
49. ENDING INVENTORY:						
50. UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105
51. UNIT COST (\$/MCF)	3.92	3.83	3.58	3.07	2.98	3.01
52. AMOUNT (\$)	1,524,320	1,490,800	1,393,600	1,193,760	1,160,400	1,170,800
53. DAYS SUPPLY:	1	1	1	1	1	1
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT (\$)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT (\$)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT (\$)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT (\$)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING

(1) LIGHT OIL-IGNITION AND ANALYSIS(2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENT(3) GAS-IGNITION

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2022 THROUGH DECEMBER 2022

	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	0	0	0	0	0	0	0
3. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT (\$)	0	0	0	0	0	0	0
5. BURNED:							
6. UNITS (BBL)	0	0	0	0	0	0	0
7. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT (\$)	0	0	0	0	0	0	0
9. ENDING INVENTORY:							
10. UNITS (BBL)	0	0	0	0	0	0	0
11. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT (\$)	0	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	665	665	665	665	665	665	7,980
16. UNIT COST (\$/BBL)	99.82	99.73	99.66	99.62	99.57	99.46	100.52
17. AMOUNT (\$)	66,383	66,323	66,277	66,250	66,212	66,144	802,137
18. BURNED:							
19. UNITS (BBL)	665	665	665	665	665	665	7,980
20. UNIT COST (\$/BBL)	133.79	133.26	132.73	132.21	131.70	131.20	134.09
21. AMOUNT (\$)	88,973	88,618	88,267	87,922	87,582	87,246	1,070,059
22. ENDING INVENTORY:							
23. UNITS (BBL)	41,760	41,760	41,760	41,760	41,760	41,760	41,760
24. UNIT COST (\$/BBL)	133.76	133.23	132.70	132.18	131.67	131.16	131.16
25. AMOUNT (\$)	5,585,850	5,563,555	5,541,565	5,519,893	5,498,523	5,477,422	5,477,422
26. DAYS SUPPLY: NORMAL	1,909,599	1,909,599	1,909,599	1,909,599	1,909,599	1,909,599	-
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
COAL							
28. PURCHASES:							
29. UNITS (TONS)	85,000	75,000	50,000	65,000	50,000	60,000	745,000
30. UNIT COST (\$/TON)	63.16	63.39	61.43	62.84	61.43	61.43	62.97
31. AMOUNT (\$)	5,368,545	4,754,278	3,071,334	4,084,755	3,071,334	3,685,601	46,910,620
32. BURNED:							
33. UNITS (TONS)	79,890	81,600	79,240	8,090	62,470	70,290	773,650
34. UNIT COST (\$/TON)	62.72	62.79	62.84	62.92	62.92	62.94	62.71
35. AMOUNT (\$)	5,010,894	5,123,910	4,979,203	509,008	3,930,668	4,423,948	48,512,588
36. ENDING INVENTORY:							
37. UNITS (TONS)	213,478	206,878	177,638	234,548	222,078	211,788	211,788
38. UNIT COST (\$/TON)	62.74	63.05	62.81	62.82	62.55	62.19	62.19
39. AMOUNT (\$)	13,392,646	13,044,122	11,156,751	14,734,591	13,891,417	13,171,253	13,171,253
40. DAYS SUPPLY:	82	113	108	153	100	92	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	12,677,295	13,146,505	11,541,635	11,241,335	8,135,455	8,409,095	122,671,541
43. UNIT COST (\$/MCF)	4.19	4.15	4.17	4.20	4.43	4.55	4.41
44. AMOUNT (\$)	53,145,337	54,542,646	48,178,436	47,195,478	36,003,650	38,286,074	541,426,764
45. BURNED:							
46. UNITS (MCF)	12,677,295	13,146,505	11,541,635	11,241,335	8,135,455	8,409,095	122,671,540
47. UNIT COST (\$/MCF)	4.19	4.15	4.17	4.20	4.42	4.55	4.42
48. AMOUNT (\$)	53,131,177	54,540,246	48,183,956	47,184,838	35,980,930	38,237,514	541,661,724
49. ENDING INVENTORY:							
50. UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105	389,105
51. UNIT COST (\$/MCF)	3.05	3.05	3.04	3.06	3.12	3.25	3.25
52. AMOUNT (\$)	1,184,960	1,187,361	1,181,839	1,192,479	1,215,200	1,263,760	1,263,760
53. DAYS SUPPLY:	1	1	1	1	1	1	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT (\$)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT (\$)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT (\$)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT (\$)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION AND ANALYSIS(2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENT (3) GAS-IGNITION

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH JUNE 2022

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT	TOTAL COST \$	GAINS ON SALES
						(A) FUEL COST	(B) TOTAL COST			
Jan-22	SEMINOLE	JURISD.	SCH. - D	2,900.0	0.0	2,900.0	3.111	3.330	90,210.00	6,358.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			2,900.0	0.0	2,900.0	3.111	3.330	90,210.00	6,358.00
Feb-22	SEMINOLE	JURISD.	SCH. - D	2,770.0	0.0	2,770.0	2.954	3.162	81,820.00	5,766.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			2,770.0	0.0	2,770.0	2.954	3.162	81,820.00	5,766.00
Mar-22	SEMINOLE	JURISD.	SCH. - D	2,990.0	0.0	2,990.0	2.887	3.091	86,330.00	6,084.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			2,990.0	0.0	2,990.0	2.887	3.091	86,330.00	6,084.00
Apr-22	SEMINOLE	JURISD.	SCH. - D	2,880.0	0.0	2,880.0	2.632	2.817	75,800.00	5,342.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			2,880.0	0.0	2,880.0	2.632	2.817	75,800.00	5,342.00
May-22	SEMINOLE	JURISD.	SCH. - D	2,880.0	0.0	2,880.0	2.822	3.021	81,270.00	5,728.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			2,880.0	0.0	2,880.0	2.822	3.021	81,270.00	5,728.00
Jun-22	SEMINOLE	JURISD.	SCH. - D	3,000.0	0.0	3,000.0	2.955	3.163	88,640.00	6,247.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			3,000.0	0.0	3,000.0	2.955	3.163	88,640.00	6,247.00

TAMPA ELECTRIC COMPANY

SCHEDULE E6

POWER SOLD

ESTIMATED FOR THE PERIOD: JULY 2022 THROUGH DECEMBER 2022

(1)	(2)	(3)		(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO	TYPE & SCHEDULE		TOTAL MWH SOLD	MWH WHEELED	MWH FROM OWN GENERATION	CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT	TOTAL COST \$	GAINS ON SALES
					FROM OTHER SYSTEMS		(A)	(B)			
							FUEL COST	TOTAL COST			
Jul-22	SEMINOLE	JURISD.	SCH. - D	2,940.0	0.0	2,940.0	2.776	2.971	81,610.00	87,362.00	5,752.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,940.0	0.0	2,940.0	2.776	2.971	81,610.00	87,362.00	5,752.00
Aug-22	SEMINOLE	JURISD.	SCH. - D	2,940.0	0.0	2,940.0	2.918	3.123	85,780.00	91,825.00	6,045.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,940.0	0.0	2,940.0	2.918	3.123	85,780.00	91,825.00	6,045.00
Sep-22	SEMINOLE	JURISD.	SCH. - D	2,960.0	0.0	2,960.0	2.720	2.911	80,500.00	86,173.00	5,673.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,960.0	0.0	2,960.0	2.720	2.911	80,500.00	86,173.00	5,673.00
Oct-22	SEMINOLE	JURISD.	SCH. - D	2,950.0	0.0	2,950.0	2.757	2.951	81,320.00	87,051.00	5,731.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,950.0	0.0	2,950.0	2.757	2.951	81,320.00	87,051.00	5,731.00
Nov-22	SEMINOLE	JURISD.	SCH. - D	2,800.0	0.0	2,800.0	2.444	2.616	68,420.00	73,242.00	4,822.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			2,800.0	0.0	2,800.0	2.444	2.616	68,420.00	73,242.00	4,822.00
Dec-22	SEMINOLE	JURISD.	SCH. - D	3,030.0	0.0	3,030.0	2.590	2.773	78,490.00	84,022.00	5,532.00
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			3,030.0	0.0	3,030.0	2.590	2.773	78,490.00	84,022.00	5,532.00
TOTAL											
Jan-22	SEMINOLE	JURISD.	SCH. - D	35,040.0	0.0	35,040.0	2.797	2.994	980,190.00	1,049,270.00	69,080.00
THRU	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
Dec-22	TOTAL			35,040.0	0.0	35,040.0	2.797	2.994	980,190.00	1,049,270.00	69,080.00

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E7

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP- TIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH		(9) TOTAL \$ FOR FUEL ADJUSTMENT
							(A) FUEL COST	(B) TOTAL COST	
Jan-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Feb-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Mar-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Apr-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
May-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Jun-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Jul-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Aug-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Sep-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Oct-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Nov-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Dec-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL Jan-22 THRU Dec-22	VARIOUS TOTAL	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL \$ FOR FUEL ADJUSTMENT
Jan-22	VARIOUS	CO-GEN. AS AVAIL.	5,660.0	0.0	0.0	5,660.0	2.637	2.637	149,230.00
	TOTAL		5,660.0	0.0	0.0	5,660.0	2.637	2.637	149,230.00
Feb-22	VARIOUS	CO-GEN. AS AVAIL.	5,670.0	0.0	0.0	5,670.0	2.454	2.454	139,130.00
	TOTAL		5,670.0	0.0	0.0	5,670.0	2.454	2.454	139,130.00
Mar-22	VARIOUS	CO-GEN. AS AVAIL.	5,910.0	0.0	0.0	5,910.0	2.783	2.783	164,470.00
	TOTAL		5,910.0	0.0	0.0	5,910.0	2.783	2.783	164,470.00
Apr-22	VARIOUS	CO-GEN. AS AVAIL.	5,670.0	0.0	0.0	5,670.0	2.500	2.500	141,730.00
	TOTAL		5,670.0	0.0	0.0	5,670.0	2.500	2.500	141,730.00
May-22	VARIOUS	CO-GEN. AS AVAIL.	5,550.0	0.0	0.0	5,550.0	2.343	2.343	130,060.00
	TOTAL		5,550.0	0.0	0.0	5,550.0	2.343	2.343	130,060.00
Jun-22	VARIOUS	CO-GEN. AS AVAIL.	5,920.0	0.0	0.0	5,920.0	2.861	2.861	169,370.00
	TOTAL		5,920.0	0.0	0.0	5,920.0	2.861	2.861	169,370.00
Jul-22	VARIOUS	CO-GEN. AS AVAIL.	5,720.0	0.0	0.0	5,720.0	2.631	2.631	150,520.00
	TOTAL		5,720.0	0.0	0.0	5,720.0	2.631	2.631	150,520.00
Aug-22	VARIOUS	CO-GEN. AS AVAIL.	5,770.0	0.0	0.0	5,770.0	3.012	3.012	173,790.00
	TOTAL		5,770.0	0.0	0.0	5,770.0	3.012	3.012	173,790.00
Sep-22	VARIOUS	CO-GEN. AS AVAIL.	5,780.0	0.0	0.0	5,780.0	3.186	3.186	184,140.00
	TOTAL		5,780.0	0.0	0.0	5,780.0	3.186	3.186	184,140.00
Oct-22	VARIOUS	CO-GEN. AS AVAIL.	5,770.0	0.0	0.0	5,770.0	2.866	2.866	165,380.00
	TOTAL		5,770.0	0.0	0.0	5,770.0	2.866	2.866	165,380.00
Nov-22	VARIOUS	CO-GEN. AS AVAIL.	5,550.0	0.0	0.0	5,550.0	2.793	2.793	154,990.00
	TOTAL		5,550.0	0.0	0.0	5,550.0	2.793	2.793	154,990.00
Dec-22	VARIOUS	CO-GEN. AS AVAIL.	5,870.0	0.0	0.0	5,870.0	2.443	2.443	143,410.00
	TOTAL		5,870.0	0.0	0.0	5,870.0	2.443	2.443	143,410.00
TOTAL Jan-22 THRU Dec-22	VARIOUS TOTAL	CO-GEN. AS AVAIL.	68,840.0	0.0	0.0	68,840.0	2.711	2.711	1,866,220.00
			68,840.0	0.0	0.0	68,840.0	2.711	2.711	1,866,220.00

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	TRANSACTION COST cents/KWH	TOTAL \$ FOR FUEL ADJUSTMENT	COST IF GENERATED		FUEL SAVINGS (9B)-(8)
								(A) CENTS PER KWH	(B) DOLLARS	
Jan-22	VARIOUS	SCH. - J	260.0	0.0	260.0	5.488	14,270.00	55.792	145,060.00	130,790.00
Feb-22	VARIOUS	SCH. - J	190.0	0.0	190.0	5.395	10,250.00	64.447	122,450.00	112,200.00
Mar-22	VARIOUS	SCH. - J	90.0	0.0	90.0	5.756	5,180.00	303.622	273,260.00	268,080.00
Apr-22	VARIOUS	SCH. - J	30.0	0.0	30.0	5.667	1,700.00	3,713.700	1,114,110.00	1,112,410.00
May-22	VARIOUS	SCH. - J	600.0	0.0	600.0	4.362	26,170.00	220.233	1,321,400.00	1,295,230.00
Jun-22	VARIOUS	SCH. - J	8,210.0	0.0	8,210.0	5.848	480,100.00	40.894	3,357,370.00	2,877,270.00
Jul-22	VARIOUS	SCH. - J	8,730.0	0.0	8,730.0	6.978	609,210.00	41.340	3,608,990.00	2,999,780.00
Aug-22	VARIOUS	SCH. - J	5,490.0	0.0	5,490.0	6.646	364,870.00	60.824	3,339,230.00	2,974,360.00
Sep-22	VARIOUS	SCH. - J	61,730.0	0.0	61,730.0	6.660	4,111,460.00	11.514	7,107,430.00	2,995,970.00
Oct-22	VARIOUS	SCH. - J	19,540.0	0.0	19,540.0	5.671	1,108,180.00	21.879	4,275,230.00	3,167,050.00
Nov-22	VARIOUS	SCH. - J	20.0	0.0	20.0	6.600	1,320.00	5,610.950	1,122,190.00	1,120,870.00
Dec-22	VARIOUS	SCH. - J	80.0	0.0	80.0	5.525	4,420.00	678.713	542,970.00	538,550.00
TOTAL	VARIOUS	SCH. - J	104,970.0	0.0	104,970.0	6.418	6,737,130.00	25.083	26,329,690.00	19,592,560.00

SCHEDULE E10

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current	Current	Projected	Difference	
	Jan 2021 - Aug 2021	Sep 2021 - Dec 2021	Jan 2022 - Dec 2022	\$	%
Base Rate Revenue	67.30	67.30	67.30	0.00	0.0%
Fuel Recovery Revenue	28.56	39.38	27.45	(11.93)	-30.3%
Conservation Revenue	1.66	1.66	2.36	0.70	42.2%
Capacity Revenue	0.02	1.70	0.31	(1.39)	-81.8%
Environmental Revenue	2.69	2.69	2.63	(0.06)	-2.2%
Storm Protection Plan Revenue	2.39	2.39	2.91	0.52	21.8%
Florida Gross Receipts Tax Revenue	2.63	2.95	2.64	(0.31)	-10.5%
TOTAL REVENUE	\$105.25	\$118.07	\$105.60	(\$12.47)	-10.6%

SCHEDULE H1

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
PERIOD: JANUARY THROUGH DECEMBER

					DIFFERENCE (%)		
	ACTUAL 2019	ACTUAL 2020	ACT/EST 2021	EST 2022	2020-2019	2021-2020	2022-2021
FUEL COST OF SYSTEM NET GENERATION (\$)							
1 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL {1}	183,150	636,201	764,784	1,070,059	247.4%	20.2%	39.9%
3 COAL	45,241,314	33,991,967	50,861,452	48,512,588	-24.9%	49.6%	-4.6%
4 NATURAL GAS	480,359,200	379,848,073	539,523,560	541,661,724	-20.9%	42.0%	0.4%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL (\$)	525,783,664	414,476,241	591,149,796	591,244,371	-21.2%	42.6%	0.0%
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL {1}	582	1,901	2,276	3,600	226.6%	19.7%	58.2%
10 COAL	1,194,254	903,680	1,402,956	1,463,780	-24.3%	55.2%	4.3%
11 NATURAL GAS	17,513,363	16,519,857	15,869,733	17,155,510	-5.7%	-3.9%	8.1%
12 NUCLEAR	756,215	1,119,822	1,430,357	2,105,180	48.1%	27.7%	47.2%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	19,464,414	18,545,260	18,705,322	20,728,070	-4.7%	0.9%	10.8%
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) {1}	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) {1}	1,436	4,345	5,444	7,980	202.6%	25.3%	46.6%
17 COAL (TON)	570,012	431,512	692,719	773,650	-24.3%	60.5%	11.7%
18 NATURAL GAS (MCF)	137,873,625	127,992,191	121,415,204	122,671,540	-7.2%	-5.1%	1.0%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
22 LIGHT OIL {1}	8,362	25,328	31,824	46,800	202.9%	25.6%	47.1%
23 COAL	13,177,799	9,830,729	15,775,515	17,407,290	-25.4%	60.5%	10.3%
24 NATURAL GAS	140,983,651	131,021,110	124,368,185	125,966,410	-7.1%	-5.1%	1.3%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	154,169,812	140,877,167	140,175,524	143,420,500	-8.6%	-0.5%	2.3%
GENERATION MIX (% MWH)							
28 HEAVY OIL {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29 LIGHT OIL {1}	0.00	0.01	0.01	0.02	0.0%	0.0%	100.0%
30 COAL	6.13	4.87	7.50	7.06	-20.6%	54.0%	-5.9%
31 NATURAL GAS	89.98	89.08	84.84	82.76	-1.0%	-4.8%	-2.5%
32 NUCLEAR	3.89	6.04	7.65	10.16	55.3%	26.7%	32.8%
33 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
34 TOTAL (%)	100.00	100.00	100.00	100.00	0.0%	0.0%	0.0%
FUEL COST PER UNIT							
35 HEAVY OIL (\$/BBL) {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36 LIGHT OIL (\$/BBL) {1}	127.54	146.42	140.48	134.09	14.8%	-4.1%	-4.5%
37 COAL (\$/TON)	79.37	78.77	73.42	62.71	-6.8%	-6.8%	-14.6%
38 NATURAL GAS (\$/MCF)	3.48	2.97	4.44	4.42	-14.7%	49.5%	-0.5%
39 NUCLEAR (\$/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU (\$/MMBTU)							
41 HEAVY OIL {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
42 LIGHT OIL {1}	21.90	25.12	24.03	22.86	14.7%	-4.3%	-4.9%
43 COAL	3.43	3.46	3.22	2.79	0.9%	-6.9%	-13.4%
44 NATURAL GAS	3.41	2.90	4.34	4.30	-15.0%	49.7%	-0.9%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL (\$/MMBTU)	3.41	2.94	4.22	4.12	-13.8%	43.5%	-2.4%
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL {1}	14,368	13,324	13,982	13,000	-7.3%	4.9%	-7.0%
50 COAL	11,034	10,879	11,244	11,892	-1.4%	3.4%	5.8%
51 NATURAL GAS	8,050	7,931	7,837	7,343	-1.5%	-1.2%	-6.3%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0	0	0	0	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	7,921	7,596	7,494	6,919	-4.1%	-1.3%	-7.7%
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
56 LIGHT OIL {1}	31.47	33.47	33.60	29.72	6.4%	0.4%	-11.5%
57 COAL	3.79	3.76	3.63	3.31	-0.8%	-3.5%	-8.8%
58 NATURAL GAS	2.74	2.30	3.40	3.16	-16.1%	47.8%	-7.1%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	2.70	2.23	3.16	2.85	-17.4%	41.7%	-9.8%

(1) DISTILLATE (BBLs, MWH & \$) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 3

**LEVELIZED AND TIERED FUEL RATE
JANUARY 2022 - DECEMBER 2022**

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period January 2022 through December 2022

	Annual Units MWH	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues \$	Tiered Fuel Rates Cents/kWh	Annual Fuel Revenues \$
Residential Excluding TOU:					
TIER I (Up to 1,000) kWh	6,622,149	3.057	202,439,095	2.745	181,777,990
TIER II (Over 1,000) kWh	3,003,068	3.057	91,803,776	3.745	112,464,881
Total	<u>9,625,217</u>		<u>294,242,871</u>		<u>294,242,871</u>

**EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE**

DOCUMENT NO. 1

**PROJECTED CAPACITY COST RECOVERY
JANUARY 2022 - DECEMBER 2022
AND
SCHEDULE E12**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2022 THROUGH DECEMBER 2022
PROJECTED

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
AVG 12 CP LOAD FACTOR AT METER (%)	PROJECTED SALES AT METER (MWH)	PROJECTED AVG 12 CP AT METER (MW)	DEMAND LOSS EXPANSION FACTOR	ENERGY LOSS EXPANSION FACTOR	PROJECTED SALES AT GENERATION (MWH)	PROJECTED AVG 12 CP AT GENERATION (MW)	PERCENTAGE OF SALES AT GENERATION (%)	PERCENTAGE OF DEMAND AT GENERATION (%)	12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	52.64%	9,728,165	1,07440	1,05326	10,246,279	2,267	49.26%	59.21%	58.44%
GS, CS	60.60%	953,392	1,07440	1,05324	1,004,152	193	4.83%	5.04%	5.02%
GSD Optional	4.44%	415,088	1,07343	1,05213	436,728	67	2.10%	1.75%	1.78%
GSD, RSD	71.44%	6,675,591	1,07343	1,05213	7,023,602	1,078	33.77%	28.15%	28.58%
GSLDPR/SBLDTPR	99.91%	1,193,640	1,04485	1,02672	1,225,538	142	5.89%	3.71%	3.88%
GSLDSU/SBLDTSU	108.11%	735,184	1,02666	1,01449	745,836	80	3.59%	2.09%	2.21%
LS1	903.21%	110,703	1,07440	1,05326	116,599	2	0.56%	0.05%	0.09%
TOTAL		19,811,763			20,798,734	3,829	100.00%	100.00%	100.00%

- (1) AVG 12 CP load factor based on 2021 projected calendar data.
(2) Projected MWH sales for the period January 2022 thru December 2022.
(3) Based on 12 months average CP at meter.
(4) Based on 2021 projected demand losses.
(5) Based on 2021 projected energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Based on 12 months average percentage of sales at generation.
(9) Based on 12 months average percentage of demand at generation.
(10) Col (8) * 0.0769 + Col (9) * 0.9231

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2022 THROUGH DECEMBER 2022
PROJECTED

	January	February	March	April	May	June	July	August	September	October	November	December	Total
1 UNIT POWER CAPACITY CHARGES	0	0	0	706,062	706,062	706,062	776,668	776,668	776,668	776,668	706,062	0	5,930,921
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3 (UNIT POWER CAPACITY REVENUES)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,176)	(62,178)	(746,114)
4 TOTAL CAPACITY DOLLARS	(\$62,176)	(\$62,176)	(\$62,176)	\$643,886	\$643,886	\$643,886	\$714,492	\$714,492	\$714,492	\$714,492	\$643,886	(\$62,178)	\$5,184,807
5 SEPARATION FACTOR	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000	
6 JURISDICTIONAL CAPACITY DOLLARS	(\$62,176)	(\$62,176)	(\$62,176)	\$643,886	\$643,886	\$643,886	\$714,492	\$714,492	\$714,492	\$714,492	\$643,886	(\$62,178)	\$5,184,806
7 ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2021 - DEC. 2021													25,180
8 SOBRA 3 TRUE-UP													(85,648)
9 TOTAL													\$5,124,338
10 REVENUE TAX FACTOR													1.00072
11 TOTAL RECOVERABLE CAPACITY DOLLARS													<u>\$5,128,028</u>

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2022 THROUGH DECEMBER 2022
PROJECTED

(1) RATE CLASS	(2) PERCENTAGE OF SALES AT GENERATION (%)	(3) ENERGY RELATED COSTS (\$)	(4) DEMAND RELATED COSTS (\$)	(5) TOTAL CAPACITY COSTS (\$)	(6) PROJECTED SALES AT METER (MWH)	(7) EFFECTIVE AT SECONDARY LEVEL (MWH)	(8) BILLING KW LOAD FACTOR (%)	(9) PROJECTED BILLED KW AT METER (kw)	(10) CAPACITY RECOVERY FACTOR (\$/kw)	(11) CAPACITY RECOVERY FACTOR (\$/kwh)
RS	49.26%	194,255	2,802,813	2,997,068	9,728,165	9,728,165				0.00031
GS, CS	4.83%	19,047	238,578	257,625	953,392	953,392				0.00027
GSD, RSD Secondary Primary Transmission									0.09 0.09 0.09	
GSD, RSD - Standard	33.77%	133,170	1,332,532	1,465,702	6,675,591	6,671,901	57.57%	15,876,488		
GSD - Optional Secondary Primary Transmission	2.10%	8,281	82,839	91,120	406,871 8,218 0	406,871 8,135 0			0.00022 0.00022 0.00022	
GSLDPR/SBLDTPR	5.89%	23,227	175,620	198,847	1,193,640	1,193,640	69.25%	2,361,119	0.08	
GSLDSU/SBLDTSU	3.59%	14,157	98,934	113,091	735,184	735,184	63.99%	1,573,784	0.07	
LS1	0.56%	2,208	2,367	4,575	110,703	110,703				0.00004
TOTAL	100.00%	394,345	4,733,683	5,128,028	19,811,763	19,807,990				0.00026

- (1) Obtained from page 1.
(2) Obtained from page 1.
(3) Total capacity costs * 0.0769 * Col (1).
(4) Total capacity costs * 0.9231 * Col (2).
(5) Col (3) + Col (4).
(6) Projected kWh sales for the period January 2022 through December 2022.
(7) Projected kWh sales at secondary for the period January 2022 through December 2022.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2022 through December 2022.
(10) Total Col (5) / Total Col (9).
(11) (Col (5) / Total Col (7)) / 1000.

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EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2022 - DECEMBER 2022

**SCHEDULES E1 THROUGH E10
SCHEDULE H1**

TAMPA ELECTRIC COMPANY

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PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1 Cost Recovery Clause Calculation	(JAN. 2022 - DEC. 2022)
3	Schedule E1-A Calculation of Total True-Up	(")
4	Schedule E1-C GPIF & True-Up Adj. Factors	(")
5	Schedule E1-D Fuel Adjustment Factor for TOD	(")
6	Schedule E1-E Fuel Recovery Factor-with Line Losses	(")
7	Schedule E2 Cost Recovery Clause Calculation (By Month)	(")
8-9	Schedule E3 Generating System Comparative Data	(")
10-33	Schedule E4 System Net Generation & Fuel Cost	(")
34-35	Schedule E5 Inventory Analysis	(")
36-37	Schedule E6 Power Sold	(")
38	Schedule E7 Purchased Power	(")
39	Schedule E8 Energy Payment to Qualifying Facilities	(")
40	Schedule E9 Economy Energy Purchases	(")
41	Schedule E10 Residential Bill Comparison	(")
42	Schedule H1 Generating System Comparative Data	(JAN. - DEC. 2019-2022)

**TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022**

SCHEDULE E1

	DOLLARS	MWH	CENTS/KWH
1. Fuel Cost of System Net Generation (E3)	591,244,371	20,728,070	2.85239
2. Nuclear Fuel Disposal Cost	0	0	0.00000
3. Coal Car Investment	0	0	0.00000
4a. Adjustment	0	20,728,070 ⁽¹⁾	0.00000
4b. Adjustment	0	0	0.00000
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)	591,244,371	20,728,070	2.85239
6. Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	0	0	0.00000
7. Energy Cost of Economy Purchases (E9)	6,737,130	104,970	6.41815
8. Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9. Energy Payments to Qualifying Facilities (E8)	1,866,220	68,840	2.71095
10. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)	8,603,350	173,810	4.94986
11. TOTAL AVAILABLE MWH (LINE 5 + LINE 10)		20,901,880	
12. Fuel Cost of Schedule D Sales - Jurisd. (E6)	980,190	35,040	2.79735
13. Fuel Cost of Market Based Sales - Jurisd. (E6)	0	0	0.00000
14. Gains on Sales	69,080	NA	NA
15. TOTAL FUEL COST AND GAINS OF POWER SALES	1,049,270	35,040	2.99449
16. Net Inadvertant Interchange		0	
17. Wheeling Received Less Wheeling Delivered		0	
18. Interchange and Wheeling Losses		1,198	
19. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)	598,798,451	20,865,642	2.86978
20. Net Unbilled	NA ^{(1)(a)}	NA ^(a)	NA
21. Company Use	1,033,121 ⁽¹⁾	36,000	0.00522
22. T & D Losses	29,337,798 ⁽¹⁾	1,022,301	0.14812
23. System MWH Sales	598,798,451	19,807,340	3.02311
24. Wholesale MWH Sales	0	0	0.00000
25. Jurisdictional MWH Sales	598,798,451	19,807,340	3.02311
26. Jurisdictional Loss Multiplier			1.00000
27. Jurisdictional MWH Sales Adjusted for Line Loss	598,798,451	19,807,340	3.02311
28. Optimization Mechanism{2}	1,285,228	19,807,340	0.00649
29. True-up (2)	325,418	19,807,340	0.00164
30. Total Jurisdictional Fuel Cost (Excl. GPIF)	600,409,097	19,807,340	3.03125
31. Revenue Tax Factor			1.00072
32. Fuel Factor (Excl. GPIF) Adjusted for Taxes	600,841,392	19,807,340	3.03343
33. GPIF Adjusted for Taxes (2)	3,673,726	19,807,340	0.01855
34. Fuel Factor Adjusted for Taxes Including GPIF	604,515,118	19,807,340	3.05198
35 Fuel Factor Rounded to Nearest .001 cents per KWH			3.052

^(a) Data not available at this time.

⁽¹⁾ Included For Informational Purposes Only

⁽²⁾ Calculation Based on Jurisdictional MWH Sales

**TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022**

SCHEDULE E1-A

1. ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2021 - December 2021 (6 months actual, 6 months estimated)	(\$44,617,507)
2. PROJECTED OVER/UNDER-RECOVERY TRUE-UP INCLUDED IN SEPTEMBER - DECEMBER 2021 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	(\$49,015,848)
3. DIFFERENCE IN 2020 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2021 RATES AND AMOUNT COLLECTED IN 2021 (\$25,479,055 under-recovery less (\$2,123,255) refunded each month January through August 2021)	<u>(\$8,493,015)</u>
4. ACTUAL-ESTIMATED 2021 OVER/(UNDER) RECOVERY (Line 1 - Line 2 + Line 3)	(\$4,094,674)
5. FINAL TRUE-UP (January 2020 - December 2020) (Per True-Up filed April 2, 2021)	<u>3,769,256</u>
6. TOTAL OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2022 (Line 4 + Line 5) To be included in the 12-month projected period January 2022 through December 2022 (2022 Schedule E1, line 29)	<u><u>(\$325,418)</u></u>
7. JURISDICTIONAL MWH SALES (Projected January 2022 through December 2022)	19,807,340
8. TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,776,928)	0.0016

**TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022**

SCHEDULE E1-C

1. TOTAL AMOUNT OF ADJUSTMENTS

A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2022 through December 2022)	\$3,673,726
B. TRUE-UP OVER / (UNDER) RECOVERED (January 2022 through December 2022)	(\$325,418)
C. OPTIMIZATION MECHANISM GAIN / (LOSS) (January 2022 through December 2022)	\$1,285,228

2. TOTAL SALES (January 2022 through December 2022)	19,807,340 MWh
--	----------------

3. ADJUSTMENT FACTORS

A. GENERATING PERFORMANCE INCENTIVE FACTOR (Using Effective MWh Sales of 19,776,928)	0.0186 Cents/kWh
B. TRUE-UP FACTOR (Using Effective MWh Sales of 19,776,928)	0.0016 Cents/kWh
C. OPTIMIZATION MECHANISM FACTOR (Using Effective MWh Sales of 19,776,928)	0.0065 Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E1-D

NET ENERGY FOR LOAD (%)	FUEL COST (%)
30.09	\$22.07
69.91	\$19.58
100.00	1.1272

ON PEAK	OFF PEAK
ON PEAK	OFF PEAK
OFF PEAK	OFF PEAK

TOTAL	ON PEAK	OFF PEAK
\$598,798,451		
19,807,340		
19,776,928		
3,0231		
1,00000		
NA		
\$325,418		
\$1,285,228		
\$600,409,097		
1,00072		
3,0381		
0,0186		
3,0567		
3,057		

1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)		
2	MWH Sales (Jurisd)	(Sch E1 line 25)		
2a	Effective MWH Sales (Jurisd)			
3	Cost Per KWH Sold	(line 1 / line 2)		
4	Jurisdictional Loss Factor			
5	Jurisdictional Fuel Factor			
6	True-Up	(Sch E1 line 29)		
7	Optimization Mechanism	(Sch E1 line 28)		
8	TOTAL	(line 1 x line 4) + line 6 + line 7		
9	Revenue Tax Factor			
10	Recovery Factor	(line 8 x line 9) / line 2a / 10		
11	GPIF Factor	(Sch E1-C line 3A)		
12	Recovery Factor Including GPIF	(line 10 + line 11)		
13	Recovery Factor Rounded to the Nearest .001 cents/KWH			

14	Hours: ON PEAK	25.60%
15	OFF PEAK	74.40%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Line Loss	Secondary
Distribution Secondary	17,502,027		17,502,027
Distribution Primary	1,569,341	0.99	1,553,647
Transmission	735,973	0.98	721,254
Total	19,807,340		19,776,928

Standard	On-Peak	Off-Peak
Distribution Secondary	3,057	2,944
Distribution Primary	3,026	2,915
Transmission	2,996	2,885
RS 1st Tier	2,745	
RS 2nd Tier	3,745	
Lighting	3,008	

SCHEDULE E1-E

**TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022**

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		2.745	3.745
Distribution Secondary	3.057		
Distribution Primary	3.026		
Transmission	2.996		
Lighting Service ⁽¹⁾	3.008		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.318		
Distribution Secondary - Off-Peak	2.944		
Distribution Primary - On-Peak	3.285		
Distribution Primary - Off-Peak	2.915		
Transmission - On-Peak	3.252		
Transmission - Off-Peak	2.885		

(1) Lighting service is based on distribution secondary, 17% on-peak and 83% off-peak

SCHEDULE E2

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	TOTAL PERIOD
1. Fuel Cost of System Net Generation	50,628,655	43,712,330	45,704,776	43,168,114	49,710,665	56,554,931	58,231,044	59,752,774	53,251,426	47,781,768	39,999,180	42,748,708	591,244,371
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold ⁽¹⁾	96,568	87,586	92,414	81,142	86,998	94,887	87,362	91,825	86,173	87,051	73,242	84,022	1,049,270
4. Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	149,230	139,130	164,470	141,730	130,060	169,370	150,520	173,790	184,140	165,380	154,960	143,410	1,866,220
7. Energy Cost of Economy Purchases	14,270	10,250	5,180	1,700	26,170	480,100	609,210	364,870	4,111,460	1,108,180	1,320	4,420	6,737,130
8. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
9. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10. TOTAL FUEL & NET POWER TRANSACTIONS	50,695,587	43,774,124	45,782,012	43,230,402	49,779,897	57,109,514	58,903,412	60,199,609	57,460,853	48,968,277	40,082,248	42,812,516	598,798,451
11. Jurisdictional MWh Sold	1,484,835	1,360,586	1,350,140	1,437,866	1,599,548	1,857,040	1,948,278	1,942,542	2,005,956	1,835,903	1,536,267	1,448,380	19,807,340
12. Jurisdictional % of Total Sales	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
13. Jurisdictional Total Fuel & Net Power Transactions (Line 10 * Line 12)	50,695,587	43,774,124	45,782,012	43,230,402	49,779,897	57,109,514	58,903,412	60,199,609	57,460,853	48,968,277	40,082,248	42,812,516	598,798,451
14. Jurisdictional Loss Multiplier	1,00000	1,00000	1,00000	1,00000	1,00000	1,00000	1,00000	1,00000	1,00000	1,00000	1,00000	1,00000	1,00000
15. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 13 * Line 14)	50,695,587	43,774,124	45,782,012	43,230,402	49,779,897	57,109,514	58,903,412	60,199,609	57,460,853	48,968,277	40,082,248	42,812,516	598,798,451
16. Cost Per kWh Sold (Cents/kWh)	3,4142	3,2173	3,3909	3,0066	3,1121	3,0753	3,0234	3,0990	2,8645	2,6673	2,6091	2,9559	3,0231
17. Optimization Mechanism (Cents/kWh) ⁽²⁾	0,0085	0,0085	0,0085	0,0085	0,0085	0,0065	0,0065	0,0065	0,0065	0,0065	0,0065	0,0065	0,0065
18. True-up (Cents/kWh) ⁽²⁾	0,0016	0,0016	0,0016	0,0016	0,0016	0,0016	0,0016	0,0016	0,0016	0,0016	0,0016	0,0016	0,0016
19. Total (Cents/kWh) (Line 16+17+18)	3,4223	3,2254	3,3990	3,0147	3,1202	3,0834	3,0315	3,1071	2,8726	2,6754	2,6172	2,9640	3,0312
20. Revenue Tax Factor	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
21. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GFP)	3,4248	3,2277	3,4014	3,0169	3,1224	3,0856	3,0337	3,1093	2,8747	2,6773	2,6191	2,9651	3,0334
22. GFP Adjusted for Taxes (Cents/kWh) ⁽²⁾	0,0186	0,0186	0,0186	0,0186	0,0186	0,0186	0,0186	0,0186	0,0186	0,0186	0,0186	0,0186	0,0186
23. TOTAL RECOVERY FACTOR (LINE 21+22)	3,4434	3,2463	3,4200	3,0355	3,1410	3,1042	3,0523	3,1279	2,8933	2,6959	2,6377	2,9847	3,0520
24. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	3,443	3,246	3,420	3,036	3,141	3,104	3,052	3,128	2,893	2,696	2,638	2,985	3,052

⁽¹⁾ Includes Gains
⁽²⁾ Based on Effective MWh Sales shown on Schedule E1-C

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH JUNE 2022

SCHEDULE E3

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
FUEL COST OF SYSTEM NET GENERATION (\$)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	91,149	90,787	90,425	90,061	89,697	89,332
3. COAL	4,505,889	3,989,914	3,561,514	3,175,693	4,571,140	4,730,807
4. NATURAL GAS	46,031,617	39,631,629	42,052,837	39,902,360	45,049,828	51,734,792
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL (\$)	50,628,655	43,712,330	45,704,776	43,168,114	49,710,665	56,554,931
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	300	300	300	300	300	300
10. COAL	136,740	118,250	106,710	92,550	136,640	144,780
11. NATURAL GAS	1,242,630	1,086,820	1,214,550	1,278,940	1,470,280	1,643,510
12. SOLAR	127,340	142,060	175,360	218,220	240,250	206,030
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	1,507,010	1,347,430	1,496,920	1,590,010	1,847,470	1,994,620
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	665	665	665	665	665	665
17. COAL (TON)	72,550	63,500	57,140	50,210	73,110	75,560
18. NATURAL GAS (MCF)	8,871,535	7,779,965	8,734,935	9,187,705	10,533,255	12,412,825
19. SOLAR	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	3,900	3,900	3,900	3,900	3,900	3,900
23. COAL	1,632,410	1,428,790	1,285,690	1,129,690	1,644,990	1,700,000
24. NATURAL GAS	9,112,610	7,990,500	8,973,090	9,437,680	10,826,040	12,738,500
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	10,748,920	9,423,190	10,262,680	10,571,270	12,474,930	14,442,400
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.02	0.02
30. COAL	9.07	8.78	7.13	5.82	7.40	7.25
31. NATURAL GAS	82.46	80.66	81.14	80.44	79.58	82.40
32. SOLAR	8.45	10.54	11.71	13.72	13.00	10.33
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT						
35. HEAVY OIL (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL (\$/BBL)	137.07	136.52	135.98	135.43	134.88	134.33
37. COAL (\$/TON)	62.11	62.83	62.33	63.25	62.52	62.61
38. NATURAL GAS (\$/MCF)	5.19	5.09	4.81	4.34	4.28	4.17
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU (\$/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	23.37	23.28	23.19	23.09	23.00	22.91
43. COAL	2.76	2.79	2.77	2.81	2.78	2.78
44. NATURAL GAS	5.05	4.96	4.69	4.23	4.16	4.06
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL (\$/MMBTU)	4.71	4.64	4.45	4.08	3.98	3.92
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000
50. COAL	11,938	12,083	12,048	12,206	12,039	11,742
51. NATURAL GAS	7,333	7,352	7,388	7,379	7,363	7,751
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	7,133	6,993	6,856	6,649	6,752	7,241
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	30.38	30.26	30.14	30.02	29.90	29.78
57. COAL	3.30	3.37	3.34	3.43	3.35	3.27
58. NATURAL GAS	3.70	3.65	3.46	3.12	3.06	3.15
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	3.36	3.24	3.05	2.71	2.69	2.84

**TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2022 THROUGH DECEMBER 2022**

SCHEDULE E3

	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	TOTAL
FUEL COST OF SYSTEM NET GENERATION (\$)							
1. HEAVY OIL	0	0	0	0	0	0	0
2. LIGHT OIL	88,973	88,618	88,267	87,922	87,582	87,246	1,070,059
3. COAL	5,010,894	5,123,910	4,979,203	509,008	3,930,668	4,423,948	48,512,588
4. NATURAL GAS	53,131,177	54,540,246	48,183,956	47,184,838	35,980,930	38,237,514	541,661,724
5. SOLAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL (\$)	58,231,044	59,752,774	53,251,426	47,781,768	39,999,180	42,748,708	591,244,371
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	0	0	0	0	0	0	0
9. LIGHT OIL	300	300	300	300	300	300	3,600
10. COAL	154,270	158,760	154,310	15,880	114,030	130,860	1,463,780
11. NATURAL GAS	1,719,190	1,762,600	1,604,070	1,634,990	1,232,580	1,265,350	17,155,510
12. SOLAR	200,630	193,910	167,470	166,660	129,810	137,440	2,105,180
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	2,074,390	2,115,570	1,926,150	1,817,830	1,476,720	1,533,950	20,728,070
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	0	0	0	0	0	0	0
16. LIGHT OIL (BBL)	665	665	665	665	665	665	7,980
17. COAL (TON)	79,890	81,600	79,240	8,090	62,470	70,290	773,650
18. NATURAL GAS (MCF)	12,677,295	13,146,505	11,541,635	11,241,335	8,135,455	8,409,095	122,671,540
19. SOLAR	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	0	0	0	0	0	0	0
22. LIGHT OIL	3,900	3,900	3,900	3,900	3,900	3,900	46,800
23. COAL	1,797,510	1,836,030	1,782,840	182,090	1,405,660	1,581,590	17,407,290
24. NATURAL GAS	13,015,500	13,496,970	11,842,940	11,543,620	8,350,810	8,638,150	125,966,410
25. SOLAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	14,816,910	15,336,900	13,629,680	11,729,610	9,760,370	10,223,640	143,420,500
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.01	0.01	0.02	0.02	0.02	0.02	0.02
30. COAL	7.44	7.50	8.01	0.87	7.72	8.53	7.06
31. NATURAL GAS	82.88	83.32	83.28	89.94	83.47	82.49	82.76
32. SOLAR	9.67	9.17	8.69	9.17	8.79	8.96	10.16
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT							
35. HEAVY OIL (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL (\$/BBL)	133.79	133.26	132.73	132.21	131.70	131.20	134.09
37. COAL (\$/TON)	62.72	62.79	62.84	62.92	62.92	62.94	62.71
38. NATURAL GAS (\$/MCF)	4.19	4.15	4.17	4.20	4.42	4.55	4.42
39. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU (\$/MMBTU)							
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	22.81	22.72	22.63	22.54	22.46	22.37	22.86
43. COAL	2.79	2.79	2.79	2.80	2.80	2.80	2.79
44. NATURAL GAS	4.08	4.04	4.07	4.09	4.31	4.43	4.30
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL (\$/MMBTU)	3.93	3.90	3.91	4.07	4.10	4.18	4.12
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	0	0	0	0	0	0	0
49. LIGHT OIL	13,000	13,000	13,000	13,000	13,000	13,000	13,000
50. COAL	11,652	11,565	11,554	11,467	12,327	12,086	11,892
51. NATURAL GAS	7,571	7,657	7,383	7,060	6,775	6,827	7,343
52. SOLAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	7,143	7,250	7,076	6,453	6,609	6,665	6,919
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	29.66	29.54	29.42	29.31	29.19	29.08	29.72
57. COAL	3.25	3.23	3.23	3.21	3.45	3.38	3.31
58. NATURAL GAS	3.09	3.09	3.00	2.89	2.92	3.02	3.16
59. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	2.81	2.82	2.76	2.63	2.71	2.79	2.85

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	270	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	190	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGALAND SOLAR	1.5	2,860	256.3	-	256.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	9,780	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,120	18.3	-	18.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	12,290	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,380	18.5	-	18.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,670	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,430	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,470	17.6	-	17.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.7	11,490	20.7	-	20.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,240	22.1	-	22.1	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,590	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,480.0	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	7,320.0	13.2	-	13.2	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	10,380.0	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	10,380.0	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	127,340	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	355	13,490	5.1	-	-	-	GAS	155,170	1,027,969	159,510.0	805,129	5.97	5.19
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	355	13,490	5.1	82.1	52.8	11,824	-	-	-	159,510.0	805,129	5.97	-
24. B.B.#4 (GAS)	160	7,200	6.0	-	-	-	GAS	83,580	1,027,997	85,920.0	433,670	6.02	5.19
25. B.B.#4 (COAL)	432	136,740	42.5	-	-	-	COAL	72,550	22,500,482	1,632,410.0	4,505,889	3.30	62.11
26. BIG BEND #4 TOTAL	432	143,940	44.8	89.3	48.9	11,938	-	-	-	1,718,330.0	4,939,559	3.43	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	7,100	1,028,169	7,300.0	36,840	-	5.19
28. B.B.C.T.#4 TOTAL	61	70	0.2	98.3	57.4	13,000	GAS	880	1,022,472	910.0	4,618	6.60	5.19
29. B.B.C.T.#5 TOTAL	350	7,140	2.7	96.0	63.8	9,821	GAS	68,210	1,028,002	70,120.0	353,920	4.96	5.19
30. B.B.C.T.#6 TOTAL	350	3,250	1.2	96.1	58.0	9,966	GAS	31,520	1,027,602	32,390.0	163,547	5.03	5.19
31. BIG BEND STATION TOTAL	1,898	167,890	11.9	74.3	49.8	11,801	-	-	-	1,981,260.0	6,303,613	3.75	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	230	5,380	3.1	-	73.1	8,959	GAS	46,880	1,028,157	48,200.0	243,246	4.52	5.19
34. POLK #1 TOTAL	230	5,380	3.1	93.8	73.1	8,959	-	-	-	48,200.0	243,246	4.52	-
35. POLK #2 ST DUCT FIRING	120	2,040	2.3	-	85.0	8,157	GAS	16,190	1,027,795	16,640.0	84,005	4.12	5.19
36. POLK #2 ST W/O DUCT FIRING	360	623,040	-	-	4,198,315	-	GAS	4,198,315	1,028,003	4,315,880.0	21,783,742	3.50	5.19
37. POLK #2 ST TOTAL	480	625,080	175.0	-	173.6	6,931	GAS	-	-	4,332,520.0	21,867,747	3.50	-
38. POLK #2 CT (GAS)	180	930	0.7	-	64.6	11,591	GAS	10,490	1,027,645	10,780.0	54,429	5.85	5.19
39. POLK #2 CT (OIL)	187	150	0.1	-	13,000	13,000	LGT OIL	333	5,855,856	1,950.0	45,643	30.43	137.07
40. POLK #2 TOTAL	⁽⁴⁾ 180	1,080	0.8	-	66.4	11,787	-	-	-	12,730.0	100,072	9.27	-
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	45,506	30.34	137.07
43. POLK #3 TOTAL	⁽⁴⁾ 180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,506	30.34	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,200	626,310	70.2	97.4	172.2	6,941	-	-	-	4,347,200.0	22,013,325	3.51	-
47. POLK STATION TOTAL	1,430	631,690	59.4	96.8	168.2	6,958	-	-	-	4,395,400.0	22,256,571	3.52	-
48. BAYSIDE #1	792	343,790	58.3	96.6	61.1	7,309	GAS	2,444,440	1,027,994	2,512,870.0	12,683,434	3.69	5.19
49. BAYSIDE #2	1,047	235,990	30.3	97.3	32.7	7,863	GAS	1,805,030	1,027,994	1,855,560.0	9,365,737	3.97	5.19
50. BAYSIDE #3	61	80	0.2	98.6	65.6	12,000	GAS	930	1,032,258	960.0	4,825	6.03	5.19
51. BAYSIDE #4	61	80	0.2	98.6	65.6	12,000	GAS	930	1,032,258	960.0	4,825	6.03	5.19
52. BAYSIDE #5	61	70	0.2	98.6	57.4	13,714	GAS	930	1,032,258	960.0	4,825	6.89	5.19
53. BAYSIDE #6	61	80	0.2	98.6	65.6	11,875	GAS	930	1,021,505	950.0	4,825	6.03	5.19
54. BAYSIDE STATION TOTAL	2,083	580,090	37.4	97.2	45.1	7,537	GAS	4,253,190	1,027,995	4,372,260.0	22,068,471	3.80	5.19
55. SYSTEM TOTAL	6,289	1,507,010	32.2	76.6	79.5	7,133	-	-	-	10,748,920.0	50,628,655	3.36	-

⁽¹⁾ As burned fuel cost system total includes ignition

⁽²⁾ Fuel burned (MM BTU) system total excludes ignition

⁽³⁾ AC rating

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	190	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,030	300.6	-	300.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	11,280	23.9	-	23.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	11,710	23.5	-	23.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,060	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	9,310	22.8	-	22.8	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	8,520	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,790	23.0	-	23.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	7,460	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
11. WIMALUA SOLAR	74.7	12,120	24.1	-	24.1	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,960	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	9,820	24.7	-	24.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,020.0	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	8,450.0	16.9	-	16.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	11,990.0	34.1	-	34.1	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	11,990.0	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	878.0	142,060	24.1	-	24.1	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	355	13,500	5.7	-	-	-	GAS	155,270	1,028,016	159,620.0	790,955	5.86	5.09
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	355	13,500	5.7	48.5	52.8	11,824	-	-	-	159,620.0	790,955	5.86	-
24. B.B.#4 (GAS)	160	6,230	5.8	-	-	-	GAS	73,150	1,027,888	75,190.0	372,630	5.98	5.09
25. B.B.#4 (COAL)	432	118,250	40.7	-	-	-	COAL	63,500	22,500,630	1,428,790.0	3,989,914	3.37	62.83
26. BIG BEND #4 TOTAL	432	124,480	42.9	89.3	46.8	12,082	-	-	-	1,503,980.0	4,362,544	3.50	-
27. BB. IGNITION	-	-	-	-	-	-	GAS	7,100	1,028,169	7,300.0	36,168	-	5.09
28. B.B.C.T.#4 TOTAL	61	10	0.0	98.3	16.4	24,000	GAS	230	1,043,478	240.0	1,172	11.72	5.10
29. B.B.C.T.#5 TOTAL	350	5,190	2.2	94.9	51.1	10,023	GAS	50,610	1,027,860	52,020.0	257,811	4.97	5.09
30. B.B.C.T.#6 TOTAL	350	1,540	0.7	96.1	55.0	9,766	GAS	14,630	1,028,025	15,040.0	74,526	4.84	5.09
31. BIG BEND STATION TOTAL	1,898	144,720	11.3	67.8	47.5	11,960	-	-	-	1,730,900.0	5,523,176	3.82	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	230	8,230	5.3	-	74.5	8,898	GAS	71,230	1,028,078	73,230.0	362,850	4.41	5.09
34. POLK #1 TOTAL	230	8,230	5.3	93.8	74.5	8,898	-	-	-	73,230.0	362,850	4.41	-
35. POLK #2 ST DUCT FIRING	120	2,260	2.8	-	75.3	8,190	GAS	18,000	1,028,333	18,510.0	91,683	4.06	5.09
36. POLK #2 ST W/ DUCT FIRING	360	555,510	-	-	-	-	-	3,742,155	1,028,001	3,846,940.0	19,062,772	3.43	5.09
37. POLK #2 ST TOTAL	480	557,770	172.9	-	172.4	6,930	GAS	-	-	3,855,450.0	19,154,465	3.43	-
38. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,462	30.31	136.52
40. POLK #2 TOTAL	180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,462	30.31	-
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	45,325	30.22	136.52
43. POLK #3 TOTAL	180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,325	30.22	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,200	558,070	69.2	97.4	172.1	6,933	-	-	-	3,869,350.0	19,246,252	3.45	-
47. POLK STATION TOTAL	1,430	566,300	58.9	96.8	165.7	6,962	-	-	-	3,942,580.0	19,608,102	3.46	-
48. BAYSIDE #1	792	276,720	52.0	96.6	56.4	7,348	GAS	1,978,040	1,028,002	2,033,430.0	10,076,260	3.64	5.09
49. BAYSIDE #2	1,047	217,230	30.9	97.3	32.2	7,879	GAS	1,664,970	1,027,994	1,711,580.0	8,481,462	3.90	5.09
50. BAYSIDE #3	61	100	0.2	98.6	82.0	12,000	GAS	1,170	1,025,641	1,200.0	5,960	5.96	5.09
51. BAYSIDE #4	61	100	0.2	98.6	82.0	11,500	GAS	1,120	1,026,786	1,150.0	5,705	5.71	5.09
52. BAYSIDE #5	61	100	0.2	98.6	82.0	11,500	GAS	1,120	1,026,786	1,150.0	5,705	5.71	5.09
53. BAYSIDE #6	61	100	0.2	98.6	82.0	12,000	GAS	1,170	1,025,641	1,200.0	5,960	5.96	5.09
54. BAYSIDE STATION TOTAL	2,083	494,350	35.3	97.2	42.4	7,585	GAS	3,647,590	1,027,997	3,749,710.0	18,581,052	3.76	5.09
55. SYSTEM TOTAL	6,289	1,347,430	31.9	74.7	78.4	6,993	-	-	-	9,423,190.0	43,712,330	3.24	-

⁽¹⁾ As burned fuel cost system total includes ignition

⁽²⁾ Fuel burned (MM BTU) system total excludes ignition

⁽³⁾ AC rating

LEGEND:

B.B. = BIG BEND

CC = COMBINED CYCLE

CT = COMBUSTION TURBINE

ST = STEAM TURBINE

⁽⁴⁾ In Simple Cycle Mode

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	330	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	230	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,060	364.3	-	364.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,260	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,750	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,290	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,050	24.5	-	24.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,120	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,280	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,770	23.9	-	23.9	-	SOLAR	-	-	-	-	-	-
11. WIMALUA SOLAR	74.7	16,460	29.7	-	29.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,360	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,640	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,720.0	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	9,900.0	17.9	-	17.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	14,060.0	36.2	-	36.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,060.0	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	878.0	175,360	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	355	13,510	5.1	-	-	-	GAS	155,390	1,027,994	159,740.0	748,099	5.54	4.81
22. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	5.54	0.00
23. BIG BEND #3 TOTAL	400	13,510	4.5	82.1	46.9	11,824	-	-	-	159,740.0	748,099	5.54	-
24. B.B.#4 (GAS)	160	5,620	4.7	-	-	-	GAS	65,820	1,028,107	67,670.0	316,879	5.64	4.81
25. B.B.#4 (COAL)	432	106,710	33.2	-	-	-	COAL	57,140	22,500,700	1,285,690.0	3,561,514	3.34	62.33
26. BIG BEND #4 TOTAL	432	112,330	35.0	72.0	47.3	12,048	-	-	-	1,353,360.0	3,876,393	3.45	-
27. BB. IGNITION	-	-	-	-	-	-	GAS	6,260	1,028,754	6,440.0	30,138	-	4.81
28. B.B.C.T.#4 TOTAL	61	10	0.0	98.3	16.4	29,000	GAS	280	1,035,714	290.0	1,348	13.48	4.81
29. B.B.C.T.#5 TOTAL	350	9,720	3.7	96.9	56.7	9,894	GAS	93,550	1,028,006	96,170.0	450,380	4.63	4.81
30. B.B.C.T.#6 TOTAL	350	4,030	1.5	96.1	52.3	10,050	GAS	39,390	1,028,160	40,500.0	189,636	4.71	4.81
31. BIG BEND STATION TOTAL	1,943	139,600	9.7	70.7	47.9	11,820	-	-	-	1,650,060.0	5,297,994	3.80	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	230	25,040	14.7	-	73.6	8,919	GAS	217,260	1,027,985	223,340.0	1,045,961	4.18	4.81
34. POLK #1 TOTAL	230	25,040	14.7	93.8	73.6	8,919	-	-	-	223,340.0	1,045,961	4.18	-
35. POLK #2 ST DUCT FIRING	120	3,610	4.0	-	79.2	8,163	GAS	28,670	1,027,904	29,470.0	138,027	3.82	4.81
36. POLK #2 ST W/ DUCT FIRING	360	510,580	-	-	-	-	GAS	3,440,515	1,028,003	3,536,860.0	16,563,765	3.24	4.81
37. POLK #2 ST TOTAL	480	514,190	144.2	-	166.3	6,936	GAS	-	-	3,566,330.0	16,701,792	3.25	-
38. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	45,281	30.19	135.98
40. POLK #2 TOTAL	180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,281	30.19	-
41. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	45,144	30.10	135.98
43. POLK #3 TOTAL	180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	45,144	30.10	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,200	514,490	57.7	81.7	166.1	6,939	-	-	-	3,570,230.0	16,792,217	3.26	-
47. POLK STATION TOTAL	1,430	539,530	50.8	83.7	148.8	7,031	-	-	-	3,793,570.0	17,838,178	3.31	-
48. BAYSIDE #1	792	345,880	58.8	96.6	60.8	7,316	GAS	2,461,540	1,027,999	2,530,460.0	11,850,659	3.43	4.81
49. BAYSIDE #2	1,047	296,530	38.1	97.3	39.2	7,716	GAS	2,225,700	1,027,996	2,288,010.0	10,715,249	3.61	4.81
50. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
51. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
52. BAYSIDE #5	61	10	0.0	96.6	16.4	29,000	GAS	280	1,035,714	290.0	1,348	13.48	4.81
53. BAYSIDE #6	61	10	0.0	96.6	16.4	29,000	GAS	280	1,035,714	290.0	1,348	13.48	4.81
54. BAYSIDE STATION TOTAL	2,083	642,430	41.5	91.4	48.5	7,501	GAS	4,687,800	1,027,998	4,819,050.0	22,568,604	3.51	4.81
55. SYSTEM TOTAL	6,334	1,496,920	31.8	70.6	79.9	6,856	-	-	-	10,262,880.0	45,704,776	3.05	-

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating
⁽⁴⁾ In Simple Cycle Mode

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
ST = STEAM TURBINE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	320	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	300	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,620	427.8	-	427.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	17,310	34.3	-	34.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	18,040	33.8	-	33.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	19,630	36.5	-	36.5	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	14,530	33.2	-	33.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	13,270	33.6	-	33.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	9,200	34.2	-	34.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	11,550	32.5	-	32.5	-	SOLAR	-	-	-	-	-	-
11. WIMALUA SOLAR	74.7	18,700	34.8	-	34.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	19,600	36.6	-	36.6	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	15,160	35.2	-	35.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	6,190.0	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	13,000.0	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	18,450.0	49.0	-	49.0	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	18,450.0	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	878.0	218,220	34.5	-	34.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	0	0	0.0	82.1	0.0	0	-	-	-	0.0	0	0.00	0.00
24. B.B.#4 (GAS)	155	4,870	4.4	-	-	-	GAS	57,840	1,028,008	59,460.0	251,201	5.16	4.34
25. B.B.#4 (COAL)	422	92,550	30.5	-	-	-	COAL	50,210	22,499,303	1,129,690.0	3,175,693	3.43	63.25
26. BIG BEND #4 TOTAL	422	97,420	32.1	65.5	47.7	12,206	-	-	-	1,189,150.0	3,426,894	3.52	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	7,100	1,026,761	7,290.0	30,835	-	4.34
28. B.B.C.T.#4 TOTAL	56	0	0.0	78.6	0.0	0	GAS	0	0	0.0	0	0.00	0.00
29. B.B.C.T.#5 TOTAL	330	32,340	13.6	95.9	100.0	9,428	GAS	296,590	1,027,985	304,890.0	1,288,095	3.98	4.34
30. B.B.C.T.#6 TOTAL	330	7,960	3.4	96.1	56.1	9,922	GAS	76,830	1,027,964	78,960.0	333,674	4.19	4.34
31. BIG BEND STATION TOTAL	1,823	137,720	10.5	67.8	54.9	11,422	-	-	-	1,573,020.0	5,079,498	3.69	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	15,840	10.5	-	80.2	8,912	GAS	137,310	1,028,039	141,160.0	596,340	3.76	4.34
34. POLK #1 TOTAL	220	15,840	10.0	93.8	80.2	8,912	-	-	-	141,160.0	596,340	3.76	-
35. POLK #2 ST DUCT FIRING	120	6,900	8.0	-	62.5	8,280	GAS	55,570	1,028,073	57,130.0	241,341	3.50	4.34
36. POLK #2 ST W/ DUCT FIRING	341	528,880	-	-	-	-	-	3,557,535	1,028,001	3,657,150.0	15,450,435	2.92	4.34
37. POLK #2 ST TOTAL	461	535,780	161.4	-	144.9	6,932	GAS	-	-	3,714,280.0	15,691,776	2.93	-
38. POLK #2 CT (GAS)	150	1,010	0.9	-	96.2	10,822	GAS	10,640	1,027,256	10,930.0	46,210	4.58	4.34
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	45,098	30.07	135.43
40. POLK #2 TOTAL	150	1,160	1.1	-	95.9	11,103	-	-	-	12,880.0	91,308	7.87	-
41. POLK #3 CT (GAS)	150	860	0.8	-	95.6	10,756	GAS	8,990	1,028,921	9,250.0	39,044	4.54	4.34
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,963	29.98	135.43
43. POLK #3 TOTAL	150	1,010	0.9	-	95.4	11,089	-	-	-	11,200.0	84,007	8.32	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	860	0.8	-	95.6	10,849	GAS	9,070	1,028,666	9,330.0	39,391	4.58	4.34
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	538,810	70.5	97.4	143.7	6,955	-	-	-	3,747,690.0	15,906,482	2.95	-
47. POLK STATION TOTAL	1,281	554,650	60.1	96.8	137.2	7,011	-	-	-	3,888,850.0	16,502,822	2.98	-
48. BAYSIDE #1	720	353,440	68.2	96.6	70.6	7,372	GAS	2,534,590	1,027,997	2,605,550.0	11,007,768	3.11	4.34
49. BAYSIDE #2	954	324,850	47.3	51.9	48.6	7,666	GAS	2,422,490	1,028,000	2,490,320.0	10,520,915	3.24	4.34
50. BAYSIDE #3	56	290	0.7	98.6	86.3	12,103	GAS	3,400	1,032,353	3,510.0	14,766	5.09	4.34
51. BAYSIDE #4	56	170	0.4	78.9	101.2	11,765	GAS	1,950	1,025,641	2,000.0	8,469	4.98	4.34
52. BAYSIDE #5	56	290	0.7	78.9	86.3	11,862	GAS	3,340	1,029,940	3,440.0	14,506	5.00	4.34
53. BAYSIDE #6	56	380	0.9	78.9	84.8	12,053	GAS	4,460	1,026,906	4,560.0	19,370	5.10	4.34
54. BAYSIDE STATION TOTAL	1,898	679,420	49.7	72.6	58.1	7,520	GAS	4,970,230	1,028,001	5,109,400.0	21,585,794	3.18	4.34
55. SYSTEM TOTAL	5,880	1,590,010	37.6	85.6	93.7	6,649	-	-	-	10,571,270.0	43,168,114	2.71	-

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating
⁽⁴⁾ In Simple Cycle Mode

LEGEND:
 B.B. = BIG BEND CT = COMBUSTION TURBINE
 CC = COMBINED CYCLE ST = STEAM TURBINE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	340	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	320	2.2	-	2.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,990	447.1	-	447.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	19,440	37.3	-	37.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	20,230	36.6	-	36.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	20,350	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	16,270	36.0	-	36.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	14,840	36.4	-	36.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	10,020	36.0	-	36.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	12,910	35.1	-	35.1	-	SOLAR	-	-	-	-	-	-
11. WIMALUA SOLAR	74.7	20,170	36.3	-	36.3	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	20,410	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	17,040	38.3	-	38.3	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	6,940.0	37.5	-	37.5	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	14,580.0	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	20,700.0	53.2	-	53.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	20,700.0	37.4	-	37.4	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	878.0	240,250	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	395	0	0.0	82.1	0.0	0	COAL	-	-	0.0	-	-	-
24. B.B.#4 (GAS)	155	7,190	6.2	-	-	-	GAS	84,220	1,028,022	86,580.0	360,201	5.01	4.28
25. B.B.#4 (COAL)	422	136,640	43.5	-	-	-	COAL	73,110	22,500,205	1,644,990.0	4,571,140	3.35	62.52
26. BIG BEND #4 TOTAL	422	143,830	45.8	89.3	50.0	12,039	COAL	-	-	1,731,570.0	4,931,341	3.43	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	2,090	1,028,708	2,150.0	8,939	-	4.28
28. B.B.C.T.#4 TOTAL	56	10	0.0	98.3	17.9	31,000	GAS	300	1,033,333	310.0	1,283	12.83	4.28
29. B.B.C.T.#5 TOTAL	330	41,580	16.9	96.9	100.0	9,424	GAS	381,160	1,027,993	391,830.0	1,630,189	3.92	4.28
30. B.B.C.T.#6 TOTAL	330	11,420	4.7	96.1	58.7	9,789	GAS	108,740	1,028,049	111,790.0	465,072	4.07	4.28
31. BIG BEND STATION TOTAL	1,873	196,840	14.1	74.4	56.4	11,357	-	-	-	2,235,500.0	7,036,824	3.57	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	6,550	4.2	-	86.6	8,777	GAS	55,920	1,028,076	57,490.0	239,165	3.65	4.28
34. POLK #1 TOTAL	220	6,550	4.0	72.6	86.6	8,777	-	-	-	57,490.0	239,165	3.65	-
35. POLK #2 ST DUCT FIRING	120	18,460	20.7	-	77.3	8,274	GAS	148,580	1,027,998	152,740.0	635,464	3.44	4.28
36. POLK #2 ST W/ DUCT FIRING	341	600,860	-	-	-	-	-	4,040,365	1,028,001	4,153,500.0	17,280,294	2.88	4.28
37. POLK #2 ST TOTAL	461	619,320	180.6	-	144.0	6,953	GAS	-	-	4,306,240.0	17,915,768	2.89	-
38. POLK #2 CT (GAS)	150	1,350	1.2	-	100.0	10,674	GAS	14,020	1,027,817	14,410.0	59,963	4.44	4.28
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,916	29.94	134.88
40. POLK #2 TOTAL	150	1,500	1.3	-	99.4	10,907	-	-	-	16,360.0	104,879	6.99	-
41. POLK #3 CT (GAS)	150	1,200	1.1	-	100.0	10,742	GAS	12,550	1,027,092	12,890.0	53,675	4.47	4.28
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,781	29.85	134.88
43. POLK #3 TOTAL	150	1,350	1.2	-	99.3	10,993	-	-	-	14,840.0	98,456	7.29	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	600	0.5	-	100.0	10,767	GAS	6,280	1,028,662	6,460.0	26,859	4.48	4.28
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	622,770	78.9	97.4	142.9	6,975	-	-	-	4,343,900.0	18,146,952	2.91	-
47. POLK STATION TOTAL	1,281	629,320	66.0	93.2	140.9	6,994	-	-	-	4,401,390.0	18,385,117	2.92	-
48. BAYSIDE #1	720	391,490	73.1	96.6	75.5	7,345	GAS	2,797,030	1,028,001	2,875,350.0	11,962,657	3.06	4.28
49. BAYSIDE #2	954	384,720	54.2	97.3	57.7	7,552	GAS	2,826,390	1,028,000	2,905,530.0	12,088,227	3.14	4.28
50. BAYSIDE #3	56	1,310	3.1	98.6	86.6	11,771	GAS	15,000	1,028,000	15,420.0	64,154	4.90	4.28
51. BAYSIDE #4	56	630	1.5	98.6	93.8	11,841	GAS	7,250	1,028,966	7,460.0	31,008	4.92	4.28
52. BAYSIDE #5	56	1,590	3.8	96.6	86.0	11,748	GAS	18,160	1,027,503	18,660.0	77,754	4.89	4.28
53. BAYSIDE #6	56	1,320	3.2	79.5	87.3	11,818	GAS	15,180	1,027,668	15,600.0	64,924	4.92	4.28
54. BAYSIDE STATION TOTAL	1,898	781,060	55.3	96.6	65.6	7,475	GAS	5,679,030	1,027,959	5,838,040.0	24,288,724	3.11	4.28
55. SYSTEM TOTAL	5,930	1,847,470	41.9	74.5	101.2	6,752	-	-	-	12,474,930.0	49,710,665	2.69	-

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating
⁽⁴⁾ In Simple Cycle Mode

LEGEND:
 B.B. = BIG BEND
 CC = COMBINED CYCLE
 CT = COMBUSTION TURBINE
 ST = STEAM TURBINE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	290	2.1	-	2.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,420	409.3	-	409.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,790	33.3	-	33.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	17,430	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,440	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	14,020	32.0	-	32.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,800	32.4	-	32.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,680	32.2	-	32.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	11,120	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
11. WIMALUA SOLAR	74.7	16,570	30.8	-	30.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,510	32.7	-	32.7	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,740	34.2	-	34.2	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	5,950.0	33.2	-	33.2	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	12,500.0	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	17,740.0	47.1	-	47.1	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	17,740.0	33.2	-	33.2	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	878.0	206,030	32.6	-	32.6	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	51,360	20.7	-	-	-	GAS	582,810	1,027,985	599,120.0	2,429,064	4.73	4.17
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	51,360	20.7	82.1	60.0	11,665	-	-	-	599,120.0	2,429,064	4.73	-
24. B.B.#4 (GAS)	155	7,620	6.8	-	-	-	GAS	87,040	1,027,918	89,470.0	362,770	4.76	4.17
25. B.B.#4 (COAL)	422	144,780	47.7	-	-	-	COAL	75,560	22,498,677	1,700,000.0	4,730,807	3.27	62.61
26. BIG BEND #4 TOTAL	422	152,400	50.2	89.3	54.7	11,742	-	-	-	1,789,470.0	5,093,577	3.34	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	21,290	1,028,182	21,890.0	88,734	-	4.17
28. B.B.C.T.#4 TOTAL	56	2,150	5.3	98.3	85.3	11,795	GAS	24,660	1,028,386	25,360.0	102,779	4.78	4.17
29. B.B.C.T.#5 TOTAL	330	52,070	21.9	96.9	22.3	11,751	GAS	595,240	1,027,989	611,900.0	2,480,871	4.76	4.17
30. B.B.C.T.#6 TOTAL	330	12,960	5.5	96.1	5.6	19,951	GAS	251,520	1,027,990	258,560.0	1,046,298	8.09	4.17
31. BIG BEND STATION TOTAL	1,823	270,940	20.6	74.1	32.5	12,122	-	-	-	3,284,410.0	11,243,323	4.15	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	59,650	39.5	-	87.1	8,781	GAS	509,530	1,028,006	523,800.0	2,123,645	3.56	4.17
34. POLK #1 TOTAL	220	59,650	37.7	93.8	87.1	8,781	-	-	-	523,800.0	2,123,645	3.56	-
35. POLK #2 ST DUCT FIRING	120	27,910	32.3	-	92.3	8,275	GAS	224,670	1,027,997	230,960.0	936,391	3.36	4.17
36. POLK #2 ST W/ DUCT FIRING	341	594,750	-	-	-	-	-	3,988,515	1,028,004	4,110,490.0	16,665,211	2.80	4.17
37. POLK #2 ST TOTAL	461	622,660	187.6	-	141.0	6,972	GAS	-	-	4,341,450.0	17,601,602	2.83	-
38. POLK #2 CT (GAS)	150	300	0.3	-	100.0	10,733	GAS	3,130	1,028,754	3,220.0	13,044	4.35	4.17
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,656	1,950.0	44,733	29.82	134.33
40. POLK #2 TOTAL	150	450	0.4	-	98.0	11,489	-	-	-	5,170.0	57,777	12.84	-
41. POLK #3 CT (GAS)	150	300	0.3	-	100.0	11,000	GAS	3,210	1,028,037	3,300.0	13,379	4.46	4.17
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,599	29.73	134.33
43. POLK #3 TOTAL	150	450	0.4	-	98.0	11,667	-	-	-	5,250.0	57,978	12.88	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	300	0.3	-	100.0	11,000	GAS	3,210	1,028,037	3,300.0	13,379	4.46	4.17
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	623,860	81.7	97.4	140.6	6,981	-	-	-	4,355,170.0	17,730,736	2.84	-
47. POLK STATION TOTAL	1,281	683,510	74.1	96.8	127.1	7,138	-	-	-	4,878,970.0	19,854,381	2.90	-
48. BAYSIDE #1	720	396,130	76.4	96.6	79.0	7,325	GAS	2,822,700	1,027,998	2,901,730.0	11,764,590	2.97	4.17
49. BAYSIDE #2	954	416,000	60.6	97.3	63.0	7,501	GAS	3,035,300	1,027,997	3,120,280.0	12,650,675	3.04	4.17
50. BAYSIDE #3	56	5,410	13.4	98.6	89.5	11,603	GAS	61,050	1,028,174	62,770.0	254,447	4.70	4.17
51. BAYSIDE #4	56	4,370	10.8	98.6	89.7	11,643	GAS	49,500	1,027,879	50,880.0	206,309	4.72	4.17
52. BAYSIDE #5	56	6,820	16.9	98.6	86.8	11,729	GAS	77,810	1,028,017	79,990.0	324,300	4.76	4.17
53. BAYSIDE #6	56	5,410	13.4	98.6	86.3	11,713	GAS	61,640	1,028,066	63,370.0	256,906	4.75	4.17
54. BAYSIDE STATION TOTAL	1,898	834,140	61.0	97.2	70.3	7,528	GAS	6,108,000	1,027,999	6,279,020.0	25,457,227	3.05	4.17
55. SYSTEM TOTAL	5,880	1,994,620	47.1	75.4	84.4	7,241	-	-	-	14,442,400.0	56,554,931	2.84	-

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating
⁽⁴⁾ In Simple Cycle Mode

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE
ST = STEAM TURBINE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	290	2.0	-	2.0	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,270	382.6	-	382.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	16,270	31.2	-	31.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,880	30.6	-	30.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	17,240	31.2	-	31.2	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,590	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	12,410	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,460	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,760	29.3	-	29.3	-	SOLAR	-	-	-	-	-	-
11. WIMALUMA SOLAR	74.7	16,330	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	17,300	31.3	-	31.3	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	14,280	32.1	-	32.1	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	5,770.0	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	12,110.0	21.9	-	21.9	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	17,190.0	44.2	-	44.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	17,190.0	31.1	-	31.1	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	878.0	200,630	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	50,200	19.6	-	-	-	GAS	580,440	1,027,996	596,690.0	2,432,654	4.85	4.19
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	50,200	19.6	82.1	55.1	11,886	-	-	-	596,690.0	2,432,654	4.85	-
24. B.B.#4 (GAS)	155	8,120	7.0	-	-	-	GAS	92,030	1,028,034	94,610.0	385,702	4.75	4.19
25. B.B.#4 (COAL)	422	154,270	49.1	-	-	-	COAL	79,890	22,499,812	1,797,510.0	5,010,894	3.25	62.72
26. BIG BEND #4 TOTAL	422	162,390	51.7	89.3	56.4	11,652	-	-	-	1,892,120.0	5,396,596	3.32	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	16,280	1,028,256	16,740.0	68,230	-	4.19
28. B.B.C.T.#4 TOTAL	56	2,830	6.8	98.3	76.6	12,155	GAS	33,460	1,028,093	34,400.0	140,233	4.96	4.19
29. B.B.C.T.#5 TOTAL	330	57,960	23.6	96.9	24.1	9,101	GAS	513,150	1,028,004	527,520.0	2,150,637	3.71	4.19
30. B.B.C.T.#6 TOTAL	330	0	0.0	96.1	0.0	0	GAS	80	1,000,000	80.0	335	0.00	4.19
31. BIG BEND STATION TOTAL	1,823	273,380	20.2	74.1	31.6	11,160	-	-	-	3,050,810.0	10,188,685	3.73	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	55,670	35.6	-	87.2	8,779	GAS	475,380	1,028,020	488,700.0	1,992,341	3.58	4.19
34. POLK #1 TOTAL	220	55,670	34.0	93.8	87.2	8,779	-	-	-	488,700.0	1,992,341	3.58	-
35. POLK #2 ST DUCT FIRING	120	28,680	32.1	-	90.5	8,275	GAS	230,850	1,028,027	237,320.0	967,504	3.37	4.19
36. POLK #2 ST W/ DUCT FIRING	341	617,480	-	-	-	-	-	4,151,525	1,028,001	4,267,770.0	17,389,249	2.82	4.19
37. POLK #2 ST TOTAL	461	646,160	188.4	-	140.4	6,972	GAS	-	-	4,505,090.0	18,366,753	2.84	-
38. POLK #2 CT (GAS)	150	1,500	1.3	-	100.0	10,700	GAS	15,620	1,027,529	16,050.0	65,464	4.36	4.19
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,553	29.70	133.79
40. POLK #2 TOTAL	150	1,650	1.5	-	99.5	10,909	-	-	-	18,000.0	110,017	6.67	-
41. POLK #3 CT (GAS)	150	1,050	0.9	-	100.0	10,686	GAS	10,910	1,028,414	11,220.0	45,724	4.35	4.19
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,420	29.61	133.80
43. POLK #3 TOTAL	150	1,200	1.1	-	99.3	10,975	-	-	-	13,170.0	90,144	7.51	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	1,350	1.2	-	100.0	10,733	GAS	14,100	1,027,660	14,490.0	59,094	4.38	4.19
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	1,200	1.1	-	100.0	10,742	GAS	12,550	1,027,092	12,890.0	52,598	4.38	4.19
46. POLK #2 CC TOTAL	1,061	651,560	82.5	97.4	139.0	7,004	-	-	-	4,563,640.0	18,678,606	2.87	-
47. POLK STATION TOTAL	1,281	707,230	74.2	96.8	127.3	7,144	-	-	-	5,052,340.0	20,670,947	2.92	-
48. BAYSIDE #1	720	416,240	77.7	96.6	80.3	7,318	GAS	2,963,250	1,028,000	3,046,220.0	12,419,129	2.98	4.19
49. BAYSIDE #2	954	452,840	63.8	97.3	65.7	7,476	GAS	3,283,140	1,028,001	3,365,350.0	13,801,715	3.05	4.19
50. BAYSIDE #3	56	5,710	13.7	98.6	84.3	11,764	GAS	65,330	1,028,165	67,170.0	273,801	4.80	4.19
51. BAYSIDE #4	56	4,890	11.7	98.6	85.6	11,722	GAS	55,780	1,027,608	57,320.0	233,777	4.78	4.19
52. BAYSIDE #5	56	7,050	16.9	98.6	86.2	11,672	GAS	60,060	1,027,654	82,290.0	335,535	4.76	4.19
53. BAYSIDE #6	56	6,420	15.4	98.6	84.3	11,746	GAS	73,360	1,027,944	75,410.0	307,455	4.79	4.19
54. BAYSIDE STATION TOTAL	1,898	893,150	63.2	97.2	72.2	7,517	GAS	6,530,920	1,027,996	6,713,760.0	27,371,412	3.06	4.19
55. SYSTEM TOTAL	5,880	2,074,390	47.4	75.4	84.5	7,143	-	-	-	14,816,910.0	58,231,044	2.81	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating
⁽⁴⁾ In Simple Cycle Mode

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	270	1.9	-	1.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	4,180	374.6	-	374.6	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	15,700	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	16,280	29.5	-	29.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	16,650	30.1	-	30.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	13,120	29.0	-	29.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	11,990	29.4	-	29.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	8,320	29.9	-	29.9	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	10,390	28.3	-	28.3	-	SOLAR	-	-	-	-	-	-
11. WIMALUA SOLAR	74.7	15,830	28.5	-	28.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	16,730	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	13,780	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	5,560.0	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	11,680.0	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	16,570.0	42.6	-	42.6	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	16,570.0	30.0	-	30.0	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	878.0	193,910	29.7	-	29.7	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	1,055	3,320	0.4	0.0	13.1	7,461	GAS	24,090	1,028,227	24,770.0	99,941	3.01	4.15
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	43,110	16.8	-	-	-	GAS	490,850	1,028,013	504,600.0	2,036,365	4.72	4.15
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	4.72	0.00
23. BIG BEND #3 TOTAL	345	43,110	16.8	82.1	58.9	11,705	-	-	-	504,600.0	2,036,365	4.72	-
24. B.B.#4 (GAS)	155	8,360	7.2	-	-	-	GAS	94,000	1,027,979	96,630.0	389,973	4.66	4.15
25. B.B.#4 (COAL)	422	158,760	50.6	-	-	-	COAL	81,600	22,500,368	1,836,030.0	5,123,910	3.23	62.79
26. BIG BEND #4 TOTAL	422	167,120	53.2	89.3	58.1	11,565	-	-	-	1,932,660.0	5,513,883	3.30	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	17,120	1,028,037	17,600.0	71,025	-	4.15
28. B.B.C.T.#4 TOTAL	56	2,870	6.9	98.3	81.3	11,969	GAS	33,420	1,027,828	34,350.0	138,648	4.83	4.15
29. B.B.C.T.#5 TOTAL	330	63,010	25.7	96.9	29.0	9,100	GAS	557,770	1,027,986	573,380.0	2,313,992	3.67	4.15
30. B.B.C.T.#6 TOTAL	330	120,960	49.3	96.1	55.6	9,101	GAS	1,070,830	1,028,006	1,100,820.0	4,442,499	3.67	4.15
31. BIG BEND STATION TOTAL	2,878	400,390	18.7	47.0	48.5	10,416	-	-	-	4,170,580.0	14,616,353	3.65	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	53,040	33.9	-	84.2	8,838	GAS	456,010	1,027,982	468,770.0	1,891,826	3.57	4.15
34. POLK #1 TOTAL	220	53,040	32.4	93.8	84.2	8,838	-	-	-	468,770.0	1,891,826	3.57	-
35. POLK #2 ST DUCT FIRING	120	21,660	24.3	-	91.6	8,277	GAS	174,410	1,027,980	179,290.0	723,566	3.34	4.15
36. POLK #2 ST W/ DUCT FIRING	341	618,070	-	-	-	-	-	4,155,105	1,028,000	4,271,450.0	17,238,076	2.79	4.15
37. POLK #2 ST TOTAL	461	639,730	186.5	-	149.1	6,957	GAS	-	-	4,450,740.0	17,961,642	2.81	-
38. POLK #2 CT (GAS)	150	1,500	1.3	-	100.0	10,727	GAS	15,660	1,027,458	16,090.0	64,967	4.33	4.15
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,375	29.58	133.26
40. POLK #2 TOTAL	150	1,650	1.5	-	99.5	10,933	-	-	-	18,040.0	109,342	6.63	-
41. POLK #3 CT (GAS)	150	1,350	1.2	-	100.0	10,733	GAS	14,100	1,027,660	14,490.0	58,496	4.33	4.15
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,243	29.50	133.26
43. POLK #3 TOTAL	150	1,500	1.3	-	99.4	10,960	-	-	-	16,440.0	102,739	6.85	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	1,350	1.2	-	100.0	10,733	GAS	14,100	1,027,660	14,490.0	58,496	4.33	4.15
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	1,200	1.1	-	100.0	10,675	GAS	12,470	1,027,265	12,810.0	51,734	4.31	4.15
46. POLK #2 CC TOTAL	1,061	645,430	81.8	97.4	147.1	6,991	-	-	-	4,512,520.0	18,283,953	2.83	-
47. POLK STATION TOTAL	1,281	698,470	73.3	96.8	132.2	7,132	-	-	-	4,981,290.0	20,175,779	2.89	-
48. BAYSIDE #1	720	387,880	72.4	96.6	78.6	7,327	GAS	2,764,590	1,027,997	2,841,990.0	11,469,316	2.96	4.15
49. BAYSIDE #2	954	418,950	59.0	97.3	61.1	7,521	GAS	3,064,920	1,027,997	3,150,730.0	12,715,280	3.04	4.15
50. BAYSIDE #3	56	3,810	9.1	98.6	81.0	11,953	GAS	44,290	1,028,223	45,540.0	183,744	4.82	4.15
51. BAYSIDE #4	56	3,250	7.8	98.6	80.6	12,049	GAS	38,080	1,028,091	39,160.0	158,022	4.86	4.15
52. BAYSIDE #5	56	4,590	11.0	98.6	76.6	12,142	GAS	54,210	1,028,039	55,730.0	224,888	4.90	4.15
53. BAYSIDE #6	56	4,320	10.4	98.6	79.5	12,009	GAS	50,470	1,027,937	51,880.0	209,362	4.85	4.15
54. BAYSIDE STATION TOTAL	1,898	822,800	58.3	97.2	68.6	7,517	GAS	6,016,570	1,027,999	6,185,030.0	24,960,642	3.03	4.15
55. SYSTEM TOTAL	6,935	2,115,570	41.0	64.0	89.3	7,250	-	-	-	15,336,900.0	59,752,774	2.82	-

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
ST = STEAM TURBINE

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating
⁽⁴⁾ In Simple Cycle Mode

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	230	1.7	-	1.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,470	321.3	-	321.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,650	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	14,140	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	14,340	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,390	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,420	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,720	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	9,030	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
11. WIMALUA SOLAR	74.7	13,680	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,370	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,890	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,830.0	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	10,150.0	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	14,400.0	38.2	-	38.2	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,400.0	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	878.0	167,470	26.5	-	26.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	1,055	296,610	39.0	0.0	40.0	6,291	GAS	1,815,250	1,028,007	1,866,090.0	7,578,296	2.55	4.17
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	48,640	19.6	-	-	-	GAS	549,750	1,027,995	565,140.0	2,295,094	4.72	4.17
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	48,640	19.6	82.1	61.0	11,619	-	0	0	565,140.0	2,295,094	4.72	-
24. B.B.#4 (GAS)	155	8,130	7.3	-	-	-	GAS	91,280	1,027,936	93,830.0	381,075	4.69	4.17
25. B.B.#4 (COAL)	422	154,310	50.8	-	-	-	COAL	79,240	22,499,243	1,782,840.0	4,979,203	3.23	62.84
26. BIG BEND #4 TOTAL	422	162,440	53.5	89.3	58.3	11,553	-	-	-	1,876,670.0	5,360,278	3.30	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	21,300	1,027,700	21,890.0	88,923	-	4.17
28. B.B.C.T.#4 TOTAL	56	8,700	21.6	98.3	86.3	11,622	GAS	98,350	1,028,063	101,110.0	410,591	4.72	4.17
29. B.B.C.T.#5 TOTAL	330	0	0.0	96.9	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. B.B.C.T.#6 TOTAL	330	0	0.0	96.1	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BIG BEND STATION TOTAL	2,878	516,390	24.9	47.0	46.5	8,538	-	-	-	4,409,010.0	15,733,182	3.05	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	54,730	36.2	-	90.8	8,696	GAS	462,980	1,027,993	475,940.0	1,932,846	3.53	4.17
34. POLK #1 TOTAL	220	54,730	34.6	93.8	90.8	8,696	-	-	-	475,940.0	1,932,846	3.53	-
35. POLK #2 ST DUCT FIRING	120	31,280	36.2	-	89.3	8,276	GAS	251,810	1,027,997	258,860.0	1,051,255	3.36	4.17
36. POLK #2 ST W/ DUCT FIRING	341	573,230	-	-	-	-	GAS	3,857,255	1,028,003	3,965,270.0	16,103,247	2.81	4.17
37. POLK #2 ST TOTAL	461	604,510	182.1	-	130.9	6,986	GAS	-	-	4,224,130.0	17,154,502	2.84	-
38. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	1	0.00	0.00
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,201	29.47	132.73
40. POLK #2 TOTAL	150	150	0.1	-	94.3	13,000	-	-	-	1,950.0	44,201	29.47	-
41. POLK #3 CT (GAS)	150	1,200	1.1	-	100.0	10,708	GAS	12,500	1,028,000	12,850.0	52,185	4.35	4.17
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	44,067	29.38	132.73
43. POLK #3 TOTAL	150	1,350	1.3	-	99.3	10,963	-	-	-	14,800.0	96,252	7.13	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	1,040	1.0	-	99.0	10,817	GAS	10,950	1,027,397	11,250.0	45,714	4.40	4.17
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	900	0.8	-	100.0	10,722	GAS	9,390	1,027,689	9,850.0	39,201	4.36	4.17
46. POLK #2 CC TOTAL	1,061	607,950	79.6	97.4	130.2	7,010	-	-	-	4,261,780.0	17,379,870	2.86	-
47. POLK STATION TOTAL	1,281	662,680	71.8	96.8	121.6	7,149	-	-	-	4,737,720.0	19,312,716	2.91	-
48. BAYSIDE #1	720	101,560	19.6	29.0	67.5	7,400	GAS	731,050	1,028,014	751,530.0	3,051,984	3.01	4.17
49. BAYSIDE #2	954	440,590	64.1	97.3	66.0	7,482	GAS	3,206,840	1,027,986	3,296,620.0	13,387,898	3.04	4.17
50. BAYSIDE #3	56	8,860	22.0	98.6	87.4	11,620	GAS	100,130	1,028,163	102,950.0	418,022	4.72	4.17
51. BAYSIDE #4	56	8,920	22.1	98.6	88.5	11,557	GAS	100,280	1,028,022	103,090.0	418,648	4.69	4.17
52. BAYSIDE #5	56	9,650	23.9	98.6	85.3	11,662	GAS	109,470	1,028,044	112,540.0	457,015	4.74	4.17
53. BAYSIDE #6	56	10,030	24.9	98.6	87.4	11,587	GAS	113,050	1,028,041	116,220.0	471,961	4.71	4.17
54. BAYSIDE STATION TOTAL	1,898	579,610	42.4	71.5	67.3	7,734	GAS	4,360,820	1,028,006	4,482,950.0	18,205,528	3.14	4.17
55. SYSTEM TOTAL	6,935	1,926,150	38.6	56.9	83.2	7,076	-	-	-	13,629,680.0	53,251,426	2.76	-

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating
⁽⁴⁾ In Simple Cycle Mode

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
ST = STEAM TURBINE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	220	1.5	-	1.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	3,590	321.7	-	321.7	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	13,490	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	13,990	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	13,980	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	11,250	24.9	-	24.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	10,300	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	7,100	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	8,930	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
11. WIMALUA SOLAR	74.7	14,210	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	14,040	25.4	-	25.4	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	11,850	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	4,790.0	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	10,070.0	18.2	-	18.2	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	14,280.0	36.7	-	36.7	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	14,280.0	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	878.0	166,660	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	1,055	664,980	84.7	0.0	86.8	6,234	GAS	4,032,710	1,028,004	4,145,640.0	16,927,062	2.55	4.20
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	44,880	17.5	-	-	-	GAS	510,250	1,028,025	524,550.0	2,141,744	4.77	4.20
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	44,880	17.5	82.1	59.4	11,688	-	-	-	524,550.0	2,141,744	4.77	-
24. B.B.#4 (GAS)	155	830	0.7	-	-	-	GAS	9,320	1,027,887	9,580.0	39,120	4.71	4.20
25. B.B.#4 (COAL)	422	15,880	5.1	-	-	-	COAL	8,090	22,508,035	182,090.0	509,008	3.21	62.92
26. BIG BEND #4 TOTAL	422	16,710	5.3	8.6	60.0	11,470	-	-	-	191,670.0	548,128	3.28	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	12,110	1,028,076	12,450.0	50,831	-	4.20
28. B.B.C.T.#4 TOTAL	56	2,180	5.2	98.3	76.3	12,197	GAS	25,880	1,027,434	26,590.0	108,630	4.98	4.20
29. B.B.C.T.#5 TOTAL	330	0	0.0	96.9	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. B.B.C.T.#6 TOTAL	330	0	0.0	96.1	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BIG BEND STATION TOTAL	2,878	728,780	34.0	35.1	83.6	6,708	-	-	-	4,888,450.0	19,776,395	2.71	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	47,070	30.1	-	83.0	8,883	GAS	406,740	1,028,003	418,130.0	1,707,267	3.63	4.20
34. POLK #1 TOTAL	220	47,070	28.8	93.8	83.0	8,883	-	-	-	418,130.0	1,707,267	3.63	-
35. POLK #2 ST DUCT FIRING	120	17,210	19.3	-	81.5	8,276	GAS	138,550	1,028,004	142,430.0	581,555	3.38	4.20
36. POLK #2 ST W/ DUCT FIRING	341	523,710	-	-	-	-	-	3,534,145	1,028,003	3,633,110.0	14,834,364	2.83	4.20
37. POLK #2 ST TOTAL	461	540,920	187.7	-	129.1	6,980	GAS	-	-	3,775,540.0	15,415,919	2.85	-
38. POLK #2 CT (GAS)	150	410	0.4	-	68.3	12,293	GAS	4,910	1,026,477	5,040.0	20,610	5.03	4.20
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	44,027	29.35	132.21
40. POLK #2 TOTAL	150	560	0.5	-	73.8	12,482	-	-	-	6,990.0	64,637	11.54	-
41. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	43,895	29.26	132.21
43. POLK #3 TOTAL	150	150	0.1	-	94.3	13,000	-	-	-	1,950.0	43,895	29.26	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	541,630	68.6	97.4	128.7	6,987	-	-	-	3,784,480.0	15,524,451	2.87	-
47. POLK STATION TOTAL	1,281	588,700	61.8	96.8	118.3	7,139	-	-	-	4,202,610.0	17,231,718	2.93	-
48. BAYSIDE #1	720	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
49. BAYSIDE #2	954	318,550	44.9	97.3	46.4	7,709	GAS	2,388,740	1,027,994	2,455,610.0	10,026,594	3.15	4.20
50. BAYSIDE #3	56	3,580	8.6	98.6	79.9	12,006	GAS	41,830	1,027,492	42,980.0	175,579	4.90	4.20
51. BAYSIDE #4	56	3,100	7.4	98.6	81.4	11,965	GAS	36,080	1,027,993	37,090.0	151,444	4.89	4.20
52. BAYSIDE #5	56	4,890	11.7	98.6	76.6	12,125	GAS	57,680	1,027,913	59,290.0	242,108	4.95	4.20
53. BAYSIDE #6	56	3,600	8.6	98.6	78.4	12,106	GAS	42,390	1,028,073	43,580.0	177,930	4.94	4.20
54. BAYSIDE STATION TOTAL	1,898	333,720	23.6	60.5	47.3	7,906	GAS	2,566,720	1,027,985	2,638,550.0	10,773,655	3.23	4.20
55. SYSTEM TOTAL	6,935	1,817,830	35.2	49.0	95.2	6,453	-	-	-	11,729,610.0	47,781,768	2.63	-

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating
⁽⁴⁾ In Simple Cycle Mode

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE
ST = STEAM TURBINE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	180	1.3	-	1.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.5	2,960	273.7	-	273.7	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	10,090	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	10,450	19.5	-	19.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	11,980	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	8,390	19.1	-	19.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	7,680	19.4	-	19.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	6,010	22.3	-	22.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	6,670	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
11. WIMAUVA SOLAR	74.7	11,740	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	12,030	22.5	-	22.5	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	8,860	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,590.0	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	7,530.0	14.1	-	14.1	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	10,690.0	28.3	-	28.3	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	10,690.0	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
18. SOLAR TOTAL	⁽³⁾ 878.0	129,810	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
19. BIG BEND #1 CC TOTAL	1,055	758,410	99.7	0.0	102.3	6,229	GAS	4,595,280	1,028,000	4,723,950.0	20,323,688	2.68	4.42
20. BIG BEND #2 TOTAL	340	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
21. B.B.#3 (GAS)	345	9,030	3.6	-	-	-	GAS	104,650	1,027,998	107,580.0	462,839	5.13	4.42
22. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
23. BIG BEND #3 TOTAL	345	9,030	3.6	43.8	54.5	11,914	-	-	-	107,580.0	462,839	5.13	-
24. B.B.#4 (GAS)	155	6,000	5.4	-	-	-	GAS	71,970	1,027,928	73,980.0	318,304	5.31	4.42
25. B.B.#4 (COAL)	422	114,030	37.5	-	-	-	COAL	62,470	22,501,361	1,405,660.0	3,830,668	3.45	62.92
26. BIG BEND #4 TOTAL	422	120,030	39.4	83.3	46.2	12,327	-	-	-	1,479,640.0	4,248,972	3.54	-
27. B.B. IGNITION	-	-	-	-	-	-	GAS	12,110	1,027,250	12,440.0	53,559	-	4.42
28. B.B.C.T.#4 TOTAL	56	110	0.3	98.3	65.5	13,091	GAS	1,400	1,028,571	1,440.0	6,192	5.63	4.42
29. B.B.C.T.#5 TOTAL	330	0	0.0	98.9	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. B.B.C.T.#6 TOTAL	330	0	0.0	96.1	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BIG BEND STATION TOTAL	2,878	887,560	42.8	41.5	87.2	7,112	-	-	-	6,312,610.0	25,095,250	2.83	-
32. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
33. POLK #1 CT (GAS)	210	7,830	5.2	-	79.3	8,921	GAS	67,950	1,027,962	69,850.0	300,525	3.84	4.42
34. POLK #1 TOTAL	220	7,830	4.9	93.8	79.3	8,921	-	-	-	69,850.0	300,525	3.84	-
35. POLK #2 ST DUCT FIRING	120	1,580	1.8	-	59.8	8,247	GAS	12,680	1,027,603	13,030.0	56,080	3.55	4.42
36. POLK #2 ST W/O DUCT FIRING	341	302,000	-	-	-	-	-	2,079,175	1,028,004	2,137,400.0	9,195,632	3.04	4.42
37. POLK #2 ST TOTAL	461	303,580	91.3	-	90.1	7,084	GAS	-	-	6,312,610.0	25,095,250	2.83	-
38. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. POLK #2 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	333	5,855,856	1,950.0	43,857	29.24	131.70
40. POLK #2 TOTAL	⁽⁴⁾ 150	150	0.1	-	94.3	13,000	-	-	-	1,950.0	43,857	29.24	-
41. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
42. POLK #3 CT (OIL)	159	150	0.1	-	94.3	13,000	LGT OIL	332	5,873,494	1,950.0	43,725	29.15	131.70
43. POLK #3 TOTAL	⁽⁴⁾ 150	150	0.1	-	94.3	13,000	-	-	-	1,950.0	43,725	29.15	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$) ⁽¹⁾	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
44. POLK #4 CT (GAS) TOTAL	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
45. POLK #5 CT (GAS) TOTAL	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #2 CC TOTAL	1,061	303,880	39.7	97.4	90.1	7,089	-	-	-	2,154,330.0	9,339,294	3.07	-
47. POLK STATION TOTAL	1,281	311,710	33.7	96.8	89.4	7,135	-	-	-	2,224,180.0	9,639,819	3.09	-
48. BAYSIDE #1	720	15,230	2.9	25.8	32.0	7,957	GAS	117,880	1,027,995	121,180.0	521,351	3.42	4.42
49. BAYSIDE #2	954	131,950	19.2	97.3	26.8	8,308	GAS	1,066,370	1,028,020	1,066,250.0	4,716,268	3.57	4.42
50. BAYSIDE #3	56	120	0.3	98.6	71.4	12,917	GAS	1,510	1,028,490	1,550.0	6,678	5.57	4.42
51. BAYSIDE #4	56	60	0.1	98.6	53.6	14,833	GAS	870	1,022,989	890.0	3,848	6.41	4.42
52. BAYSIDE #5	56	140	0.3	98.6	62.5	14,071	GAS	1,920	1,026,042	1,970.0	8,492	6.07	4.42
53. BAYSIDE #6	56	120	0.3	98.6	53.6	14,500	GAS	1,690	1,028,586	1,740.0	7,474	6.23	4.42
54. BAYSIDE STATION TOTAL	1,898	147,620	10.8	70.3	27.3	8,289	GAS	1,190,240	1,028,011	1,223,580.0	5,264,111	3.57	4.42
55. SYSTEM TOTAL	6,935	1,476,720	29.5	54.3	81.4	6,609	-	-	-	9,760,370.0	39,999,180	2.71	-

(1) As burned fuel cost system total includes ignition
(2) Fuel burned (MM BTU) system total excludes ignition
(3) AC rating
(4) In Simple Cycle Mode

CT = COMBUSTION TURBINE
ST = STEAM TURBINE

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
1. TIA SOLAR	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.3	160	1.1	-	1.1	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	2.880	240.1	1.5	-	240.1	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	70.1	8,470	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	74.2	8,770	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	74.3	10,360	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	60.8	7,030	15.5	-	15.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.8	6,450	15.8	-	15.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	37.4	5,030	18.1	-	18.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	49.4	5,800	15.2	-	15.2	-	SOLAR	-	-	-	-	-	-
11. WIMALUA SOLAR	74.7	10,430	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.3	10,410	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
13. DURRANCE SOLAR	59.8	7,440	16.7	-	16.7	-	SOLAR	-	-	-	-	-	-
14. FUTURE SOLAR	24.9	3,010	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
15. FUTURE SOLAR	74.3	6,320	11.4	-	11.4	-	SOLAR	-	-	-	-	-	-
16. FUTURE SOLAR	52.3	8,970	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
17. FUTURE SOLAR	74.3	8,970	16.2	-	16.2	-	SOLAR	-	-	-	-	-	-
18. FUTURE SOLAR	22.2	7,860	47.6	-	47.6	-	SOLAR	-	-	-	-	-	-
19. FUTURE SOLAR	65.0	8,080	16.7	-	16.7	-	SOLAR	-	-	-	-	-	-
20. FUTURE SOLAR	70.0	2,680	5.1	-	5.1	-	SOLAR	-	-	-	-	-	-
21. FUTURE SOLAR	66.8	8,460	17.0	-	17.0	-	SOLAR	-	-	-	-	-	-
22. SOLAR TOTAL	1102.0	137,440	16.8	-	16.8	-	SOLAR	-	-	-	-	-	-
23. BIG BEND #1 CC TOTAL	1,120	787,780	94.5	98.0	96.9	6,277	GAS	4,810,060	1,028,002	4,944,750.0	21,872,120	2.78	4.55
24. BIG BEND #2 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
25. B.B.#3 (GAS)	355	13,470	5.1	-	-	-	GAS	155,030	1,028,059	159,380.0	704,947	5.23	4.55
26. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	-	0.0	0	0.00	0.00
27. BIG BEND #3 TOTAL	355	13,470	5.1	82.1	52.7	11,832	-	-	-	159,380.0	704,947	5.23	-
28. B.B.#4 (GAS)	160	6,890	5.8	-	-	-	GAS	80,970	1,028,035	83,240.0	388,184	5.34	4.55
29. B.B.#4 (COAL)	432	130,860	40.7	-	-	-	COAL	70,280	22,500,925	1,581,590.0	4,423,948	3.38	62.94
30. BIG BEND #4 TOTAL	432	137,750	42.9	89.3	46.8	12,086	-	-	-	1,664,830.0	4,792,132	3.48	-
31. B.B. IGNITION	-	-	-	-	-	-	GAS	6,260	1,028,754	6,440.0	28,465	-	4.55
32. B.B.C.T.#4 TOTAL	61	430	0.9	98.3	88.1	11,628	GAS	4,880	1,024,590	5,000.0	22,190	5.16	4.55
33. B.B.C.T.#5 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. B.B.C.T.#6 TOTAL	350	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. BIG BEND STATION TOTAL	3,018	939,430	41.8	60.8	82.9	7,211	-	-	-	6,773,960.0	27,419,854	2.92	-
36. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
37. POLK #1 CT (GAS)	230	21,630	12.6	-	73.5	8,961	GAS	188,540	1,028,058	193,830.0	857,322	3.96	4.55
38. POLK #1 TOTAL	230	21,630	12.6	93.8	73.5	8,961	-	-	-	193,830.0	857,322	3.96	-
39. POLK #2 ST DUCT FIRING	120	2,310	2.6	-	83.7	8,182	GAS	18,380	1,028,292	18,900.0	83,577	3.62	4.55
40. POLK #2 ST W/DUCT FIRING	360	239,370	-	-	-	-	GAS	1,659,095	1,028,006	1,705,560.0	7,544,173	3.15	4.55
41. POLK #2 ST TOTAL	480	241,680	67.7	-	80.6	7,135	-	-	-	1,724,460.0	7,627,750	3.16	-
42. POLK #2 CT (GAS)	180	1,580	1.2	-	67.5	11,652	GAS	17,900	1,028,492	18,410.0	81,393	5.15	4.55
43. POLK #2 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	333	5,855,856	1,950.0	43,688	29.13	131.20
44. POLK #2 TOTAL	180	1,730	1.3	-	68.5	11,769	-	-	-	20,360.0	125,081	7.23	-
45. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
46. POLK #3 CT (OIL)	187	150	0.1	-	80.2	13,000	LGT OIL	332	5,873,494	1,950.0	43,558	29.04	131.20
47. POLK #3 TOTAL	180	150	0.1	-	80.2	13,000	-	-	-	1,950.0	43,558	29.04	-

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2022

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA- BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) ⁽²⁾	AS BURNED FUEL COST (\$ ⁽¹⁾)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL (\$/UNIT)
48. POLK #4 CT (GAS) TOTAL	⁽⁴⁾ 180	940	0.7	-	65.3	11,681	GAS	10,680	1,028,090	10,980.0	48,564	5.17	4.55
49. POLK #5 CT (GAS) TOTAL	⁽⁴⁾ 180	930	0.7	-	64.6	11,806	GAS	10,680	1,028,090	10,980.0	48,564	5.22	4.55
50. POLK #2 CC TOTAL	1,200	245,430	27.5	81.7	79.9	7,207	-	-	-	1,768,730.0	7,893,517	3.22	-
51. POLK STATION TOTAL	1,430	267,060	25.1	83.7	78.9	7,349	-	-	-	1,962,560.0	8,750,839	3.28	-
52. BAYSIDE #1	792	137,370	23.3	96.6	32.7	7,702	GAS	1,029,200	1,028,002	1,058,020.0	4,679,939	3.41	4.55
53. BAYSIDE #2	1,047	51,050	6.6	97.3	28.3	8,042	GAS	399,370	1,027,994	410,550.0	1,815,999	3.56	4.55
54. BAYSIDE #3	61	380	0.8	98.6	89.0	11,342	GAS	4,190	1,028,640	4,310.0	19,053	5.01	4.55
55. BAYSIDE #4	61	330	0.7	98.6	90.2	11,485	GAS	3,680	1,027,100	3,790.0	16,779	5.08	4.55
56. BAYSIDE #5	61	470	1.0	98.6	85.6	11,723	GAS	5,360	1,027,985	5,510.0	24,373	5.19	4.55
57. BAYSIDE #6	61	420	0.9	98.6	86.1	11,762	GAS	4,810	1,027,027	4,940.0	21,872	5.21	4.55
58. BAYSIDE STATION TOTAL	2,083	190,020	12.3	97.2	31.5	7,826	GAS	1,446,620	1,027,996	1,487,120.0	6,578,015	3.46	4.55
59. SYSTEM TOTAL	7,633	1,533,950	27.0	86.2	77.1	6,665	-	-	-	10,223,640.0	42,748,708	2.79	-

⁽¹⁾ As burned fuel cost system total includes ignition
⁽²⁾ Fuel burned (MM BTU) system total excludes ignition
⁽³⁾ AC rating
⁽⁴⁾ In Simple Cycle Mode

LEGEND:
B.B. = BIG BEND
CC = COMBINED CYCLE
CT = COMBUSTION TURBINE
ST = STEAM TURBINE

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH JUNE 2022

SCHEDULE E5

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT (\$)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT (\$)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT (\$)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	665	665	665	665	665	665
16. UNIT COST (\$/BBL)	102.65	102.38	101.85	101.07	100.43	99.96
17. AMOUNT (\$)	68,265	68,083	67,728	67,209	66,788	66,475
18. BURNED:						
19. UNITS (BBL)	665	665	665	665	665	665
20. UNIT COST (\$/BBL)	137.07	136.52	135.98	135.43	134.88	134.33
21. AMOUNT (\$)	91,149	90,787	90,425	90,061	89,697	89,332
22. ENDING INVENTORY:						
23. UNITS (BBL)	41,760	41,760	41,760	41,760	41,760	41,760
24. UNIT COST (\$/BBL)	137.03	136.49	135.94	135.40	134.85	134.30
25. AMOUNT (\$)	5,722,460	5,699,756	5,677,059	5,654,207	5,631,298	5,608,440
26. DAYS SUPPLY: NORMAL	1,909,609	1,909,599	1,909,599	1,909,599	1,909,599	1,909,599
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	65,000	55,000	70,000	70,000	55,000	45,000
30. UNIT COST (\$/TON)	64.46	63.99	63.38	63.47	64.03	61.43
31. AMOUNT (\$)	4,190,125	3,519,461	4,436,677	4,442,855	3,521,454	2,764,201
32. BURNED:						
33. UNITS (TONS)	72,550	63,500	57,140	50,210	73,110	75,560
34. UNIT COST (\$/TON)	62.11	62.83	62.33	63.25	62.52	62.61
35. AMOUNT (\$)	4,505,889	3,989,914	3,561,514	3,175,693	4,571,140	4,730,807
36. ENDING INVENTORY:						
37. UNITS (TONS)	232,888	224,388	237,248	257,038	238,928	208,368
38. UNIT COST (\$/TON)	60.96	61.42	61.84	62.22	62.62	62.46
39. AMOUNT (\$)	14,196,096	13,782,069	14,672,013	15,992,163	14,961,389	13,014,329
40. DAYS SUPPLY:	108	117	121	118	96	81
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	8,871,536	7,779,965	8,734,935	9,187,705	10,533,255	12,412,825
43. UNIT COST (\$/MCF)	5.19	5.09	4.80	4.32	4.27	4.17
44. AMOUNT (\$)	46,057,217	39,598,109	41,955,637	39,702,520	45,016,467	51,745,193
45. BURNED:						
46. UNITS (MCF)	8,871,535	7,779,965	8,734,935	9,187,705	10,533,255	12,412,825
47. UNIT COST (\$/MCF)	5.19	5.09	4.81	4.34	4.28	4.17
48. AMOUNT (\$)	46,031,617	39,631,629	42,052,837	39,902,360	45,049,828	51,734,792
49. ENDING INVENTORY:						
50. UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105
51. UNIT COST (\$/MCF)	3.92	3.83	3.58	3.07	2.98	3.01
52. AMOUNT (\$)	1,524,320	1,490,800	1,393,600	1,193,760	1,160,400	1,170,800
53. DAYS SUPPLY:	1	1	1	1	1	1
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT (\$)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT (\$)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT (\$)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT (\$)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION AND ANALYSIS(2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENT (3) GAS-IGNITION

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2022 THROUGH DECEMBER 2022

	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	0	0	0	0	0	0	0
3. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT (\$)	0	0	0	0	0	0	0
5. BURNED:							
6. UNITS (BBL)	0	0	0	0	0	0	0
7. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT (\$)	0	0	0	0	0	0	0
9. ENDING INVENTORY:							
10. UNITS (BBL)	0	0	0	0	0	0	0
11. UNIT COST (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT (\$)	0	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	665	665	665	665	665	665	7,980
16. UNIT COST (\$/BBL)	99.82	99.73	99.66	99.62	99.57	99.46	100.52
17. AMOUNT (\$)	66,383	66,323	66,277	66,250	66,212	66,144	802,137
18. BURNED:							
19. UNITS (BBL)	665	665	665	665	665	665	7,980
20. UNIT COST (\$/BBL)	133.79	133.26	132.73	132.21	131.70	131.20	134.09
21. AMOUNT (\$)	88,973	88,618	88,267	87,922	87,582	87,246	1,070,059
22. ENDING INVENTORY:							
23. UNITS (BBL)	41,760	41,760	41,760	41,760	41,760	41,760	41,760
24. UNIT COST (\$/BBL)	133.76	133.23	132.70	132.18	131.67	131.16	131.16
25. AMOUNT (\$)	5,585,850	5,563,555	5,541,565	5,519,893	5,498,523	5,477,422	5,477,422
26. DAYS SUPPLY: NORMAL	1,909,599	1,909,599	1,909,599	1,909,599	1,909,599	1,909,599	-
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
COAL							
28. PURCHASES:							
29. UNITS (TONS)	85,000	75,000	50,000	65,000	50,000	60,000	745,000
30. UNIT COST (\$/TON)	63.16	63.39	61.43	62.84	61.43	61.43	62.97
31. AMOUNT (\$)	5,368,545	4,754,278	3,071,334	4,084,755	3,071,334	3,685,601	46,910,620
32. BURNED:							
33. UNITS (TONS)	79,890	81,600	79,240	8,090	62,470	70,290	773,650
34. UNIT COST (\$/TON)	62.72	62.79	62.84	62.92	62.92	62.94	62.71
35. AMOUNT (\$)	5,010,894	5,123,910	4,979,203	509,008	3,930,668	4,423,948	48,512,588
36. ENDING INVENTORY:							
37. UNITS (TONS)	213,478	206,878	177,638	234,548	222,078	211,788	211,788
38. UNIT COST (\$/TON)	62.74	63.05	62.81	62.82	62.55	62.19	62.19
39. AMOUNT (\$)	13,392,646	13,044,122	11,156,751	14,734,591	13,891,417	13,171,253	13,171,253
40. DAYS SUPPLY:	82	113	108	153	100	92	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	12,677,295	13,146,505	11,541,635	11,241,335	8,135,455	8,409,095	122,671,541
43. UNIT COST (\$/MCF)	4.19	4.15	4.17	4.20	4.43	4.55	4.41
44. AMOUNT (\$)	53,145,337	54,542,646	48,178,436	47,195,478	36,003,650	38,286,074	541,426,764
45. BURNED:							
46. UNITS (MCF)	12,677,295	13,146,505	11,541,635	11,241,335	8,135,455	8,409,095	122,671,540
47. UNIT COST (\$/MCF)	4.19	4.15	4.17	4.20	4.42	4.55	4.42
48. AMOUNT (\$)	53,131,177	54,540,246	48,183,956	47,184,838	35,980,930	38,237,514	541,661,724
49. ENDING INVENTORY:							
50. UNITS (MCF)	389,105	389,105	389,105	389,105	389,105	389,105	389,105
51. UNIT COST (\$/MCF)	3.05	3.05	3.04	3.06	3.12	3.25	3.25
52. AMOUNT (\$)	1,184,960	1,187,361	1,181,839	1,192,479	1,215,200	1,263,760	1,263,760
53. DAYS SUPPLY:	1	1	1	1	1	1	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT (\$)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT (\$)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT (\$)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST (\$/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT (\$)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION AND ANALYSIS(2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENT (3) GAS-IGNITION

TAMPA ELECTRIC COMPANY POWER SOLD ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH JUNE 2022										SCHEDULE E6
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
		TYPE & SCHEDULE	TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	FROM OWN GENERATION	CENTS/KWH (A) FUEL (B) TOTAL COST	TOTAL \$ FOR FUEL ADJUSTMENT	TOTAL COST \$	GAINS ON SALES	
Jan-22	SEMINOLE JURISD.	SCH. -D	2,900.0	0.0	2,900.0	3.111	3.330	90,210.00	96,568.00	6,358.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		2,900.0	0.0	2,900.0	3.111	3.330	90,210.00	96,568.00	6,358.00
Feb-22	SEMINOLE JURISD.	SCH. -D	2,770.0	0.0	2,770.0	2.954	3.162	81,820.00	87,586.00	5,766.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		2,770.0	0.0	2,770.0	2.954	3.162	81,820.00	87,586.00	5,766.00
Mar-22	SEMINOLE JURISD.	SCH. -D	2,990.0	0.0	2,990.0	2.887	3.091	86,330.00	92,414.00	6,084.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		2,990.0	0.0	2,990.0	2.887	3.091	86,330.00	92,414.00	6,084.00
Apr-22	SEMINOLE JURISD.	SCH. -D	2,880.0	0.0	2,880.0	2.632	2.817	75,800.00	81,142.00	5,342.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		2,880.0	0.0	2,880.0	2.632	2.817	75,800.00	81,142.00	5,342.00
May-22	SEMINOLE JURISD.	SCH. -D	2,880.0	0.0	2,880.0	2.822	3.021	81,270.00	86,998.00	5,728.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		2,880.0	0.0	2,880.0	2.822	3.021	81,270.00	86,998.00	5,728.00
Jun-22	SEMINOLE JURISD.	SCH. -D	3,000.0	0.0	3,000.0	2.955	3.163	88,640.00	94,887.00	6,247.00
	VARIOUS JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		3,000.0	0.0	3,000.0	2.955	3.163	88,640.00	94,887.00	6,247.00

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2022 THROUGH DECEMBER 2022

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)	
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	WHEELED FROM		MWH FROM OWN GENERATION	CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT	TOTAL COST \$	GAINSON SALES
				OTHER	SYSTEMS		FUEL	TOTAL			
				THRU	THRU		THRU	THRU			
Jul-22	SEMINOLE	JURISD. SCH. - D	2,940.0	0.0	2,940.0	2.776	2.971	81,610.00	87,362.00	5,752.00	
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	
	TOTAL		2,940.0	0.0	2,940.0	2.776	2.971	81,610.00	87,362.00	5,752.00	
Aug-22	SEMINOLE	JURISD. SCH. - D	2,940.0	0.0	2,940.0	2.918	3.123	85,780.00	91,825.00	6,045.00	
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	
	TOTAL		2,940.0	0.0	2,940.0	2.918	3.123	85,780.00	91,825.00	6,045.00	
Sep-22	SEMINOLE	JURISD. SCH. - D	2,960.0	0.0	2,960.0	2.720	2.911	80,500.00	86,173.00	5,673.00	
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	
	TOTAL		2,960.0	0.0	2,960.0	2.720	2.911	80,500.00	86,173.00	5,673.00	
Oct-22	SEMINOLE	JURISD. SCH. - D	2,950.0	0.0	2,950.0	2.757	2.951	81,320.00	87,051.00	5,731.00	
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	
	TOTAL		2,950.0	0.0	2,950.0	2.757	2.951	81,320.00	87,051.00	5,731.00	
Nov-22	SEMINOLE	JURISD. SCH. - D	2,800.0	0.0	2,800.0	2.444	2.616	68,420.00	73,242.00	4,822.00	
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	
	TOTAL		2,800.0	0.0	2,800.0	2.444	2.616	68,420.00	73,242.00	4,822.00	
Dec-22	SEMINOLE	JURISD. SCH. - D	3,030.0	0.0	3,030.0	2.590	2.773	78,490.00	84,022.00	5,532.00	
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	
	TOTAL		3,030.0	0.0	3,030.0	2.590	2.773	78,490.00	84,022.00	5,532.00	
TOTAL											
Jan-22	SEMINOLE	JURISD. SCH. - D	35,040.0	0.0	35,040.0	2.797	2.994	980,190.00	1,049,270.00	69,080.00	
THRU	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	
Dec-22	TOTAL		35,040.0	0.0	35,040.0	2.797	2.994	980,190.00	1,049,270.00	69,080.00	

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT
							(A) FUEL COST	(B) TOTAL COST	
Jan-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Feb-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Mar-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Apr-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
May-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Jun-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Jul-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Aug-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Sep-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Oct-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Nov-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Dec-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL									
Jan-22	VARIOUS	FIRM	0.0	0.0	0.0	0.0	0.000	0.000	0.00
THRU	TOTAL		0.0	0.0	0.0	0.0	0.000	0.000	0.00
Dec-22									

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH		TOTAL \$ FOR FUEL ADJUSTMENT
							(A) FUEL COST	(B) TOTAL COST	
Jan-22	VARIOUS	CO-GEN. AS AVAIL.	5,660.0	0.0	0.0	5,660.0	2.637	2.637	149,230.00
	TOTAL		5,660.0	0.0	0.0	5,660.0	2.637	2.637	149,230.00
Feb-22	VARIOUS	CO-GEN. AS AVAIL.	5,670.0	0.0	0.0	5,670.0	2.454	2.454	139,130.00
	TOTAL		5,670.0	0.0	0.0	5,670.0	2.454	2.454	139,130.00
Mar-22	VARIOUS	CO-GEN. AS AVAIL.	5,910.0	0.0	0.0	5,910.0	2.783	2.783	164,470.00
	TOTAL		5,910.0	0.0	0.0	5,910.0	2.783	2.783	164,470.00
Apr-22	VARIOUS	CO-GEN. AS AVAIL.	5,670.0	0.0	0.0	5,670.0	2.500	2.500	141,730.00
	TOTAL		5,670.0	0.0	0.0	5,670.0	2.500	2.500	141,730.00
May-22	VARIOUS	CO-GEN. AS AVAIL.	5,550.0	0.0	0.0	5,550.0	2.343	2.343	130,060.00
	TOTAL		5,550.0	0.0	0.0	5,550.0	2.343	2.343	130,060.00
Jun-22	VARIOUS	CO-GEN. AS AVAIL.	5,920.0	0.0	0.0	5,920.0	2.861	2.861	169,370.00
	TOTAL		5,920.0	0.0	0.0	5,920.0	2.861	2.861	169,370.00
Jul-22	VARIOUS	CO-GEN. AS AVAIL.	5,720.0	0.0	0.0	5,720.0	2.631	2.631	150,520.00
	TOTAL		5,720.0	0.0	0.0	5,720.0	2.631	2.631	150,520.00
Aug-22	VARIOUS	CO-GEN. AS AVAIL.	5,770.0	0.0	0.0	5,770.0	3.012	3.012	173,790.00
	TOTAL		5,770.0	0.0	0.0	5,770.0	3.012	3.012	173,790.00
Sep-22	VARIOUS	CO-GEN. AS AVAIL.	5,780.0	0.0	0.0	5,780.0	3.186	3.186	184,140.00
	TOTAL		5,780.0	0.0	0.0	5,780.0	3.186	3.186	184,140.00
Oct-22	VARIOUS	CO-GEN. AS AVAIL.	5,770.0	0.0	0.0	5,770.0	2.866	2.866	165,380.00
	TOTAL		5,770.0	0.0	0.0	5,770.0	2.866	2.866	165,380.00
Nov-22	VARIOUS	CO-GEN. AS AVAIL.	5,550.0	0.0	0.0	5,550.0	2.793	2.793	154,990.00
	TOTAL		5,550.0	0.0	0.0	5,550.0	2.793	2.793	154,990.00
Dec-22	VARIOUS	CO-GEN. AS AVAIL.	5,870.0	0.0	0.0	5,870.0	2.443	2.443	143,410.00
	TOTAL		5,870.0	0.0	0.0	5,870.0	2.443	2.443	143,410.00
TOTAL Jan-22 THRU Dec-22	VARIOUS	CO-GEN. AS AVAIL.	68,840.0	0.0	0.0	68,840.0	2.711	2.711	1,866,220.00
	TOTAL		68,840.0	0.0	0.0	68,840.0	2.711	2.711	1,866,220.00

TAMPA ELECTRIC COMPANY ECONOMY ENERGY PURCHASES ESTIMATED FOR THE PERIOD: JANUARY 2022 THROUGH DECEMBER 2022										SCHEDULE E9
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	TRANSACTIONAL COST cents/KWH	TOTAL \$ FOR FUEL ADJUSTMENT	COST IF GENERATED (A) CENTS PER KWH	(B) DOLLARS	FUEL SAVINGS (9B)-(8)
Jan-22	VARIOUS	SCH. - J	260.0	0.0	260.0	5.488	14,270.00	55.792	145,060.00	130,790.00
Feb-22	VARIOUS	SCH. - J	190.0	0.0	190.0	5.395	10,250.00	64.447	122,450.00	112,200.00
Mar-22	VARIOUS	SCH. - J	90.0	0.0	90.0	5.756	5,180.00	303.622	273,260.00	268,080.00
Apr-22	VARIOUS	SCH. - J	30.0	0.0	30.0	5.667	1,700.00	3,713.700	1,114,110.00	1,112,410.00
May-22	VARIOUS	SCH. - J	600.0	0.0	600.0	4.362	26,170.00	220.233	1,321,400.00	1,295,230.00
Jun-22	VARIOUS	SCH. - J	8,210.0	0.0	8,210.0	5.848	480,100.00	40.894	3,357,370.00	2,877,270.00
Jul-22	VARIOUS	SCH. - J	8,730.0	0.0	8,730.0	6.978	609,210.00	41.340	3,608,990.00	2,999,780.00
Aug-22	VARIOUS	SCH. - J	5,490.0	0.0	5,490.0	6.646	364,870.00	60.824	3,339,230.00	2,974,360.00
Sep-22	VARIOUS	SCH. - J	61,730.0	0.0	61,730.0	6.660	4,111,460.00	11.514	7,107,430.00	2,995,970.00
Oct-22	VARIOUS	SCH. - J	19,540.0	0.0	19,540.0	5.671	1,108,180.00	21.879	4,275,230.00	3,167,050.00
Nov-22	VARIOUS	SCH. - J	20.0	0.0	20.0	6.600	1,320.00	5,610.950	1,122,190.00	1,120,870.00
Dec-22	VARIOUS	SCH. - J	80.0	0.0	80.0	5.525	4,420.00	678.713	542,970.00	538,550.00
TOTAL		SCH. - J	104,970.0	0.0	104,970.0	6.418	6,737,130.00	25.083	26,329,690.00	19,592,560.00

SCHEDULE E10

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current		Projected		Difference	
	Jan 2021 - Aug 2021	Sep 2021 - Dec 2021	Jan 2022 - Dec 2022		\$	%
Base Rate Revenue	67.30	67.30	78.69	11.39	11.39	16.9%
Fuel Recovery Revenue	28.56	39.38	27.45	(11.93)	(11.93)	-30.3%
Conservation Revenue	1.66	1.66	2.36	0.70	0.70	42.2%
Capacity Revenue	0.02	1.70	0.31	(1.39)	(1.39)	-81.8%
Environmental Revenue	2.69	2.69	1.38	(1.31)	(1.31)	-48.7%
Storm Protection Plan Revenue	2.39	2.39	3.31	0.92	0.92	38.5%
Clean Energy Transition Mechanism	0.00	0.00	4.41	4.41	4.41	0.0%
Florida Gross Receipts Tax Revenue	2.63	2.95	3.02	0.07	0.07	2.4%
TOTAL REVENUE	\$105.25	\$118.07	\$120.93	\$2.86	\$2.86	2.4%

SCHEDULE H1

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
PERIOD: JANUARY THROUGH DECEMBER

					DIFFERENCE (%)		
	ACTUAL 2019	ACTUAL 2020	ACT/EST 2021	EST 2022	2020-2019	2021-2020	2022-2021
FUEL COST OF SYSTEM NET GENERATION (\$)							
1 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL {1}	183,150	636,201	764,784	1,070,059	247.4%	20.2%	39.9%
3 COAL	45,241,314	33,991,967	50,861,452	48,512,588	-24.9%	49.6%	-4.6%
4 NATURAL GAS	480,359,200	379,848,073	539,523,560	541,661,724	-20.9%	42.0%	0.4%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL (\$)	525,783,664	414,476,241	591,149,796	591,244,371	-21.2%	42.6%	0.0%
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL {1}	582	1,901	2,276	3,600	226.6%	19.7%	58.2%
10 COAL	1,194,254	903,680	1,402,956	1,463,780	-24.3%	55.2%	4.3%
11 NATURAL GAS	17,513,363	16,519,857	15,869,733	17,155,510	-5.7%	-3.9%	8.1%
12 NUCLEAR	756,215	1,119,822	1,430,357	2,105,180	48.1%	27.7%	47.2%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	19,464,414	18,545,260	18,705,322	20,728,070	-4.7%	0.9%	10.8%
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) {1}	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) {1}	1,436	4,345	5,444	7,980	202.6%	25.3%	46.6%
17 COAL (TON)	570,012	431,512	692,719	773,650	-24.3%	60.5%	11.7%
18 NATURAL GAS (MCF)	137,873,625	127,992,191	121,415,204	122,671,540	-7.2%	-5.1%	1.0%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
22 LIGHT OIL {1}	8,362	25,328	31,824	46,800	202.9%	25.6%	47.1%
23 COAL	13,177,799	9,830,729	15,775,515	17,407,290	-25.4%	60.5%	10.3%
24 NATURAL GAS	140,983,651	131,021,110	124,368,185	125,966,410	-7.1%	-5.1%	1.3%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	154,169,812	140,877,167	140,175,524	143,420,500	-8.6%	-0.5%	2.3%
GENERATION MIX (% MWH)							
28 HEAVY OIL {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29 LIGHT OIL {1}	0.00	0.01	0.01	0.02	0.0%	0.0%	100.0%
30 COAL	6.13	4.87	7.50	7.06	-20.6%	54.0%	-5.9%
31 NATURAL GAS	89.98	89.08	84.84	82.76	-1.0%	-4.8%	-2.5%
32 NUCLEAR	3.89	6.04	7.65	10.16	55.3%	26.7%	32.8%
33 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
34 TOTAL (%)	100.00	100.00	100.00	100.00	0.0%	0.0%	0.0%
FUEL COST PER UNIT							
35 HEAVY OIL (\$/BBL) {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36 LIGHT OIL (\$/BBL) {1}	127.54	146.42	140.48	134.09	14.8%	-4.1%	-4.5%
37 COAL (\$/TON)	79.37	78.77	73.42	62.71	-0.8%	-6.8%	-14.6%
38 NATURAL GAS (\$/MCF)	3.48	2.97	4.44	4.42	-14.7%	49.5%	-0.5%
39 NUCLEAR (\$/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU (\$/MMBTU)							
41 HEAVY OIL {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
42 LIGHT OIL {1}	21.90	25.12	24.03	22.86	14.7%	-4.3%	-4.9%
43 COAL	3.43	3.46	3.22	2.79	0.9%	-6.9%	-13.4%
44 NATURAL GAS	3.41	2.90	4.34	4.30	-15.0%	49.7%	-0.9%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL (\$/MMBTU)	3.41	2.94	4.22	4.12	-13.8%	43.5%	-2.4%
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL {1}	14,368	13,324	13,982	13,000	-7.3%	4.9%	-7.0%
50 COAL	11,034	10,879	11,244	11,892	-1.4%	3.4%	5.8%
51 NATURAL GAS	8,050	7,931	7,837	7,343	-1.5%	-1.2%	-6.3%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0	0	0	0	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	7,921	7,596	7,494	6,919	-4.1%	-1.3%	-7.7%
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL {1}	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
56 LIGHT OIL {1}	31.47	33.47	33.60	29.72	6.4%	0.4%	-11.5%
57 COAL	3.79	3.76	3.63	3.31	-0.8%	-3.5%	-8.8%
58 NATURAL GAS	2.74	2.30	3.40	3.16	-16.1%	47.8%	-7.1%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	2.70	2.23	3.16	2.85	-17.4%	41.7%	-9.8%

(1) DISTILLATE (BBLs, MWH & \$) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

EXHIBIT TO THE TESTIMONY OF

M. ASHLEY SIZEMORE

DOCUMENT NO. 3

LEVELIZED AND TIERED FUEL RATE

JANUARY 2022 - DECEMBER 2022

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period January 2022 through December 2022

	Annual Units MWh	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues \$	Tiered Fuel Rates Cents/kWh	Annual Fuel Revenues \$
Residential Excluding TOU:					
TIER I (Up to 1,000) kWh	6,622,149	3.057	202,439,095	2.745	181,777,990
TIER II (Over 1,000) kWh	3,003,068	3.057	91,803,776	3.745	112,464,881
Total	<u>9,625,217</u>		<u>294,242,871</u>		<u>294,242,871</u>

GENERATING PERFORMANCE INCENTIVE FACTOR

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2	Actual Unit Performance Data	35

**EXHIBIT NO. PAB-1
TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
GPIF 2020 FINAL TRUE-UP
DOCUMENT NO. 1**

**EXHIBIT TO THE TESTIMONY OF
PATRICK A. BOKOR**

DOCKET NO. 20210001-EI

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2020 – DECEMBER 2020
TRUE-UP**

**DOCUMENT NO. 1
GPIF SCHEDULES**

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2020 - DECEMBER 2020
TRUE-UP
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**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2020 - DECEMBER 2020**

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) (\$000)	GENERATING PERFORMANCE INCENTIVE FACTOR (\$000)
+10	21,602.7	10,801.4
+9	19,442.5	9,721.2
+8	17,282.2	8,641.1
+7	15,121.9	7,561.0
+6	12,961.6	6,480.8
+5	10,801.4	5,400.7
+4	8,641.1	4,320.5
+3	6,480.8	3,240.4
+2	4,320.5	2,160.3
+1	2,160.3	1,080.1
0	0.0	0.0
-1	(1,976.7)	(1,080.1)
-2	(3,953.4)	(2,160.3)
-3	(5,930.1)	(3,240.4)
-4	(7,906.8)	(4,320.5)
-5	(9,883.5)	(5,400.7)
-6	(11,860.2)	(6,480.8)
-7	(13,836.9)	(7,561.0)
-8	(15,813.6)	(8,641.1)
-9	(17,790.3)	(9,721.2)
-10	(19,767.0)	(10,801.4)

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2020 - DECEMBER 2020**

Line 1	Beginning of period balance of common equity: End of month common equity:	\$ 3,164,685,873	
Line 2	Month of January 2020	\$ 3,187,189,753	
Line 3	Month of February 2020	\$ 3,247,212,391	
Line 4	Month of March 2020	\$ 3,267,864,918	
Line 5	Month of April 2020	\$ 3,293,474,028	
Line 6	Month of May 2020	\$ 3,359,088,486	
Line 7	Month of June 2020	\$ 3,404,579,841	
Line 8	Month of July 2020	\$ 3,451,123,043	
Line 9	Month of August 2020	\$ 3,482,696,331	
Line 10	Month of September 2020	\$ 3,520,228,750	
Line 11	Month of October 2020	\$ 3,558,468,419	
Line 12	Month of November 2020	\$ 3,543,220,019	
Line 13	Month of December 2020	\$ 3,554,661,131	
Line 14	(Summation of line 1 through line 13 divided by 13)	\$ 3,387,268,691	
Line 15	25 Basis points	0.0025	
Line 16	Revenue Expansion Factor	75.30%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)	\$ 11,246,360	
Line 18	Jurisdictional Sales	19,950,343	MWH
Line 19	Total Sales	19,950,343	MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	100.00%	
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)	\$ 11,246,360	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-Point level from Sheet No. 3.515)	\$ 10,801,371	
Line 23	Maximum Allowed GPIF Reward (At 10 GPIF-Point Level; the lesser of line 21 and line 22)	\$ 10,801,371	

**TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2020 - DECEMBER 2020**

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
BIG BEND 4	47.0%	EAF	1.40%	-7.439	-0.104
POLK 1	67.6%	EAF	3.15%	-10.000	-0.315
POLK 2	80.4%	EAF	6.84%	-10.000	-0.684
BAYSIDE 1	90.5%	EAF	5.63%	-8.818	-0.496
BAYSIDE 2	88.5%	EAF	8.39%	-1.618	-0.136
BIG BEND 4	10,972	ANOHR	4.43%	-1.710	-0.076
POLK 1	8,698	ANOHR	11.15%	9.319	1.039
POLK 2	6,843	ANOHR	35.96%	9.141	3.287
BAYSIDE 1	7,336	ANOHR	7.64%	0.000	0.000
BAYSIDE 2	7,324	ANOHR	15.43%	5.742	0.886
			100.00%		3.401

GPIF REWARD

\$ 3,673,726

**TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY**

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF MAX. (%)	RANGE MIN. (%)	MAX. FUEL SAVINGS (\$000)	MAX. FUEL LOSS (\$000)	EAF ADJUSTED ACTUAL (%)	EST. FUEL SAVINGS/ LOSS (\$000)
BIG BEND 4	1.40%	55.39	61.0	44.1	301.8	(1,622.9)	47.0%	(1,207.2)
POLK 1	3.15%	75.5	79.1	68.3	680.0	(107.9)	67.6%	(107.9)
POLK 2	6.84%	84.9	86.1	82.7	1,477.8	(823.7)	80.4%	(823.7)
BAYSIDE 1	5.63%	91.7	92.4	90.3	1,216.3	(475.9)	90.5%	(419.6)
BAYSIDE 2	<u>8.39%</u>	88.9	90.1	86.4	<u>1,811.8</u>	<u>(621.7)</u>	88.5%	(100.6)
GPIF SYSTEM	25.40%				5,487.8	(3,652.1)		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	TARGET		ANOHR TARGET RANGE		MAX. FUEL SAVINGS (\$000)	MAX. FUEL LOSS (\$000)	ACTUAL ADJUSTED ANOHR	EST. FUEL SAVINGS/ LOSS (\$000)
		ANOHR (Btu/kwh)	NOF (%)	MIN.	MAX.				
BIG BEND 4	4.43%	10,837	52.3	10,410	11,264	956.4	(956.4)	10,972	(163.6)
POLK 1	11.15%	10,018	84.8	8,607	11,429	2,408.6	(2,408.6)	8,698	2,244.6
POLK 2	35.96%	7,209	72.9	6,816	7,603	7,768.2	(7,768.2)	6,843	7,101.0
BAYSIDE 1	7.64%	7,379	84.2	7,260	7,498	1,649.5	(1,649.5)	7,336	0.0
BAYSIDE 2	<u>15.43%</u>	7,499	70.9	7,250	7,749	<u>3,332.3</u>	<u>(3,332.3)</u>	7,324	1,913.4
GPIF SYSTEM	74.60%					16,115.0	(16,115.0)		

**TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2020 - DECEMBER 2020**

<u>PLANT / UNIT</u>	<u>ACTUAL EAF (%)</u>	<u>ADJUSTMENTS (1) TO EAF (%)</u>	<u>EAF ADJUSTED ACTUAL (%)</u>
BIG BEND 4	35.7	11.3	47.0
POLK 1	69.9	-2.3	67.6
POLK 2	89.5	-9.1	80.4
BAYSIDE 1	89.5	1.0	90.5
BAYSIDE 2	90.6	-2.1	88.5

<u>PLANT / UNIT</u>	<u>ACTUAL ANOHR (Btu/kwh)</u>	<u>ADJUSTMENTS (2) TO ANOHR (Btu/kwh)</u>	<u>ANOHR ADJUSTED ACTUAL (Btu/kwh)</u>
BIG BEND 4	10,928	44	10,972
POLK 1	8,862	-164	8,698
POLK 2	7,089	-246	6,843
BAYSIDE 1	7,412	-76	7,336
BAYSIDE 2	7,398	-74	7,324

(1) Documentation of adjustments to Actual EAF on pages 7 - 11

(2) Documentation of adjustments to Actual ANOHR on pages 12 - 16

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 4
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 1.40%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>	<u>ADJUSTED ACTUAL PERFORMANCE</u>
PH	8,784.0	8,784.0	8,784.0
EAF	55.4	35.7	47.0
POH	1,919.0	3,262.2	1,919.0
FOH + EFOH	1,362.5	1,490.8	1,853.4
MOH + EMOH	636.7	711.7	884.8
POF	21.8	37.1	21.8
EFOF	15.5	17.0	21.1
EMOF	7.2	8.1	10.1
	-7.439	EQUIVALENT AVAILABILITY POINTS	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 1919}{8784 - 3262.2} \times (1490.8 + 711.7) = 2,738.3$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 21.8 - \frac{2,738.3}{8,784.0} \times 100 = 47.0$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 1
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 3.15%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>	<u>ADJUSTED ACTUAL PERFORMANCE</u>
PH	8,784.0	8,784.0	8,784.0
EAF	75.5	69.9	67.6
POH	744.0	467.8	744.0
FOH + EFOH	744.5	1,700.6	1,644.1
MOH + EMOH	661.6	471.7	456.0
POF	8.5	5.3	8.5
EFOF	8.5	19.4	18.7
EMOF	7.5	5.4	5.2
	-10.000	EQUIVALENT AVAILABILITY POINTS	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 744}{8784 - 467.8} \times (1700.6 + 471.7) = 2,100.2$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 8.5 - \frac{2100.2}{8,784.0} \times 100 = 67.6$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 2
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 6.84%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>	<u>ADJUSTED ACTUAL PERFORMANCE</u>
PH	8,784.0	8,784.0	8,784.0
EAF	84.9	89.5	80.4
POH	1,104.0	246.0	1,104.0
FOH + EFOH	110.1	464.3	417.6
MOH + EMOH	110.4	215.3	193.7
POF	12.6	2.8	12.6
EFOF	1.3	5.3	4.8
EMOF	1.3	2.5	2.2
	-10.000	EQUIVALENT AVAILABILITY POINTS	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 1104}{8784 - 246} \times (464.3 + 215.3) = 611.3$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 12.6 - \frac{611.3}{8,784.0} \times 100 = 80.4$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 1
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 5.63%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>	<u>ADJUSTED ACTUAL PERFORMANCE</u>
PH	8,784.0	8,784.0	8,784.0
EAF	91.7	89.5	90.5
POH	576.0	673.8	576.0
FOH + EFOH	42.2	137.2	138.9
MOH + EMOH	111.5	113.8	115.2
POF	6.6	7.7	6.6
EFOF	0.5	1.6	1.6
EMOF	1.3	1.3	1.3
	-8.818	EQUIVALENT AVAILABILITY POINTS	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 576}{8784 - 673.8} \times (137.2 + 113.8) = 254.0$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{254.0}{8,784.0} \times 100 = 90.5$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 2
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 8.39%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>	<u>ADJUSTED ACTUAL PERFORMANCE</u>
PH	8,784.0	8,784.0	8,784.0
EAF	88.9	90.6	88.5
POH	576.0	381.3	576.0
FOH + EFOH	179.5	69.5	67.9
MOH + EMOH	219.6	370.9	362.3
POF	6.6	4.3	6.6
EFOF	2.0	0.8	0.8
EMOF	2.5	4.2	4.1
	-1.618	EQUIVALENT AVAILABILITY POINTS	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 576}{8784 - 381.3} \times (69.5 + 370.9) = 430.2$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{430.2}{8,784.0} \times 100 = 88.5$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 4
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 4.43%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>
ANOHR (Btu/kwh)	10,837	10,928
NET GENERATION (GWH)	708.3	1,054.1
OPERATING BTU (10 ⁹)	8,920.0	11,518.9
NET OUTPUT FACTOR	52.3	60.8

-1.710 HEAT RATE POINTS

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: $\text{NOF} * (-5.26) + 11111.91 = \text{ANOHR}$

$$60.8 * (-5.26) + 11111.91 = 10,792$$

$$10,928 - 10,792 = 136$$

$$10,837 + 136 = 10,972 \quad \leftarrow \text{ADJUSTED ACTUAL HEAT RATE AT TARGET NOF}$$

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 1
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 11.15%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>
ANOHR (Btu/kwh)	10,018	8,862
NET GENERATION (GWH)	561.9	587.1
OPERATING BTU (10 ⁹)	4,692.2	5,202.9
NET OUTPUT FACTOR	84.8	70.3

9.319 HEAT RATE POINTS

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: $\text{NOF} * (-11.27) + 10973.68 = \text{ANOHR}$

$$70.3 * (-11.27) + 10973.68 = 10,182$$

$$8,862 - 10,182 = -1320$$

$$10,018 + -1320 = 8,698 \quad \leftarrow \text{ADJUSTED ACTUAL HEAT RATE AT TARGET NOF}$$

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 2
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 35.96%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>
ANOHR (Btu/kwh)	7,209	7,089
NET GENERATION (GWH)	6,763.2	6,134.1
OPERATING BTU (10 ⁹)	48,041.5	43,484.4
NET OUTPUT FACTOR	72.9	67.5

9.141 HEAT RATE POINTS

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: $\text{NOF} * (-45.56) + 10530.02 = \text{ANOHR}$

$$67.5 * (-45.56) + 10530.02 = 7,455$$

$$7,089 - 7,455 = -366$$

$$7,209 + -366 = 6,843 \quad \leftarrow \text{ADJUSTED ACTUAL HEAT RATE AT TARGET NOF}$$

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 1
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 7.64%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>
ANOHR (Btu/kwh)	7,379	7,412
NET GENERATION (GWH)	4,945.8	3,144.2
OPERATING BTU (10 ⁹)	35,983.7	23,305.7
NET OUTPUT FACTOR	84.2	58.8

0.000 HEAT RATE POINTS

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: $\text{NOF} * (-3) + 7631.21 = \text{ANOHR}$

$58.8 * (-3) + 7631.21 = 7,455$

$7,412 - 7,455 = -43$

$7,379 + -43 = 7,336$ ← ADJUSTED ACTUAL
HEAT RATE AT
TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

**TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 2
JANUARY 2020 - DECEMBER 2020**

WEIGHTING FACTOR = 15.43%

	<u>12 MONTH TARGET</u>	<u>12 MONTH ACTUAL PERFORMANCE</u>
ANOHR (Btu/kwh)	7,499	7,398
NET GENERATION (GWH)	4,752.5	4,398.7
OPERATING BTU (10 ⁹)	35,301.0	32,540.1
NET OUTPUT FACTOR	70.9	59.8

5.742 HEAT RATE POINTS

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: $\text{NOF} * (-6.67) + 7971.73 = \text{ANOHR}$

$$59.8 * (-6.67) + 7971.73 = 7,573$$

$$7,398 - 7,573 = -175$$

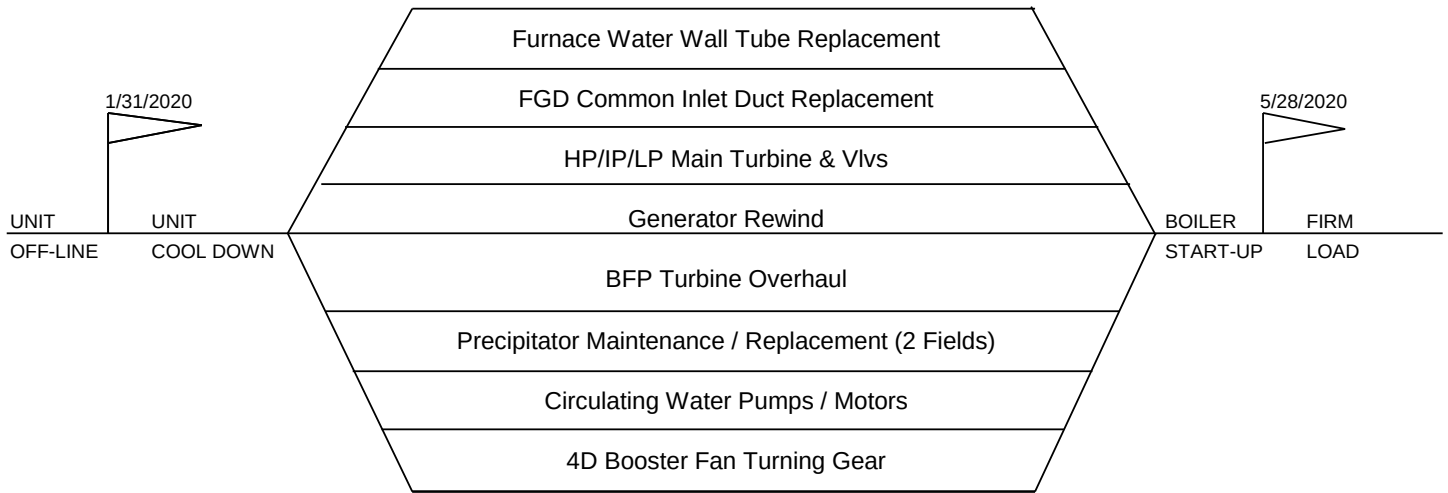
$$7,499 + -175 = 7,324 \quad \leftarrow \text{ADJUSTED ACTUAL HEAT RATE AT TARGET NOF}$$

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

**TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2020 - DECEMBER 2020**

<u>PLANT / UNIT</u>	<u>PLANNED OUTAGE DATES</u>	<u>OUTAGE DESCRIPTION</u>
+ BIG BEND 4	Jan 31 - May 28	Furnace Water Wall Tube Replacement, FGD Common Inlet Duct Replacement, Precipitator Maintenance, BFP Turbine Overhaul, 4D Booster Fan Turning Gear, Circulating Water Pumps / Motors, HP/IP/LP Main Turbine & Vlvs, Generator Rewind
	Oct 16 - Nov 02	Fuel System Clean-up
POLK 1	Nov 16 - Dec 05	Combined Cycle & Gasifier
POLK 2	-	Simple Cycle
BAYSIDE 1	Feb 27 - Mar 12	Combined Cycle
	Dec 01 - Dec 14	Combined Cycle
BAYSIDE 2	Nov 10 - Dec 05	Combined Cycle
+ CPM for units with less than or equal to 4 weeks are not included.		

**TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2020 - DECEMBER 2020**



TAMPA ELECTRIC COMPANY
BIG BEND 4
PLANNED OUTAGE 2020
PROJECTED CPM

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2020 - DECEMBER 2020

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	301.8	61.0	+10	956.4	10,410
+9	271.6	60.5	+9	860.7	10,445
+8	241.4	59.9	+8	765.1	10,480
+7	211.2	59.3	+7	669.5	10,516
+6	181.1	58.8	+6	573.8	10,551
+5	150.9	58.2	+5	478.2	10,586
+4	120.7	57.7	+4	382.5	10,621
+3	90.5	57.1	+3	286.9	10,656
+2	60.4	56.5	+2	191.3	10,691
+1	30.2	56.0	+1	95.6	10,727
					10,762
0	0.0	55.4	0	0.0	10,837
					10,912
-1	(162.3)	54.3	-1	(95.6)	10,947
-2	(324.6)	53.1	-2	(191.3)	10,982
-3	(486.9)	52.0	-3	(286.9)	11,017
-4	(649.2)	50.9	-4	(382.5)	11,053
-5	(811.5)	49.8	-5	(478.2)	11,088
-6	(973.7)	48.6	-6	(573.8)	11,123
-7	(1,136.0)	47.5	-7	(669.5)	11,158
-8	(1,298.3)	46.4	-8	(765.1)	11,193
-9	(1,460.6)	45.2	-9	(860.7)	11,228
-10	(1,622.9)	44.1	-10	(956.4)	11,264

AHR
POINTS
-1.710

Adjusted
ANOHR
10,972

EAF
POINTS
-7.439

Adjusted
EAF
47.0

Weighting Factor =

1.40%

Weighting Factor =

4.43%

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2020 - DECEMBER 2020

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	680.0	79.1	+10	2,408.6	8,607
+9	612.0	78.8	+9	2,167.7	8,741
+8	544.0	78.4	+8	1,926.9	8,874
+7	476.0	78.1	+7	1,686.0	9,008
+6	408.0	77.7	+6	1,445.2	9,141
+5	340.0	77.3	+5	1,204.3	9,275
+4	272.0	77.0	+4	963.4	9,409
+3	204.0	76.6	+3	722.6	9,542
+2	136.0	76.2	+2	481.7	9,676
+1	68.0	75.9	+1	240.9	9,809
					9,943
0	0.0	75.5	0	0.0	10,018
					10,093
-1	(10.8)	74.8	-1	(240.9)	10,226
-2	(21.6)	74.1	-2	(481.7)	10,360
-3	(32.4)	73.3	-3	(722.6)	10,494
-4	(43.1)	72.6	-4	(963.4)	10,627
-5	(53.9)	71.9	-5	(1,204.3)	10,761
-6	(64.7)	71.2	-6	(1,445.2)	10,894
-7	(75.5)	70.4	-7	(1,686.0)	11,028
-8	(86.3)	69.7	-8	(1,926.9)	11,162
-9	(97.1)	69.0	-9	(2,167.7)	11,295
-10	(107.9)	68.3	-10	(2,408.6)	11,429

Weighting Factor =

3.15%

Weighting Factor =

11.15%

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2020 - DECEMBER 2020

POLK 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,477.8	86.1	+10	7,768.2	6,816
+9	1,330.1	85.9	+9	6,991.4	6,847
+8	1,182.3	85.8	+8	6,214.6	6,879
+7	1,034.5	85.7	+7	5,437.8	6,911
+6	886.7	85.6	+6	4,660.9	6,943
+5	738.9	85.5	+5	3,884.1	6,975
+4	591.1	85.4	+4	3,107.3	7,007
+3	443.4	85.3	+3	2,330.5	7,039
+2	295.6	85.1	+2	1,553.6	7,071
+1	147.8	85.0	+1	776.8	7,102
					7,134
0	0.0	84.9	0	0.0	7,209
					7,284
-1	(82.4)	84.7	-1	(776.8)	7,316
-2	(164.7)	84.5	-2	(1,553.6)	7,348
-3	(247.1)	84.2	-3	(2,330.5)	7,380
-4	(329.5)	84.0	-4	(3,107.3)	7,412
-5	(411.9)	83.8	-5	(3,884.1)	7,444
-6	(494.2)	83.6	-6	(4,660.9)	7,475
-7	(576.6)	83.3	-7	(5,437.8)	7,507
-8	(659.0)	83.1	-8	(6,214.6)	7,539
-9	(741.4)	82.9	-9	(6,991.4)	7,571
-10	(823.7)	82.7	-10	(7,768.2)	7,603

**EAF
POINTS
-10.000**

Weighting Factor =

**Adjusted
EAF
80.4**

6.84%

Weighting Factor =

35.96%

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2020 - DECEMBER 2020

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,216.3	92.4	+10	1,649.5	7,260
+9	1,094.7	92.3	+9	1,484.5	7,265
+8	973.1	92.2	+8	1,319.6	7,269
+7	851.4	92.2	+7	1,154.6	7,273
+6	729.8	92.1	+6	989.7	7,278
+5	608.2	92.0	+5	824.7	7,282
+4	486.5	92.0	+4	659.8	7,286
+3	364.9	91.9	+3	494.8	7,291
+2	243.3	91.8	+2	329.9	7,295
+1	121.6	91.8	+1	164.9	7,300
				AHR POINTS 0.000	Adjusted ANOHR 7,336
0	0.0	91.7	0	0.0	7,304
					7,379
					7,454
-1	(47.6)	91.6	-1	(164.9)	7,458
-2	(95.2)	91.4	-2	(329.9)	7,463
-3	(142.8)	91.3	-3	(494.8)	7,467
-4	(190.3)	91.2	-4	(659.8)	7,471
-5	(237.9)	91.0	-5	(824.7)	7,476
-6	(285.5)	90.9	-6	(989.7)	7,480
-7	(333.1)	90.7	-7	(1,154.6)	7,484
	→ EAF POINTS -8.818 ←				
-8	(380.7)	90.6	-8	(1,319.6)	7,489
		Adjusted EAF 90.5 →			
-9	(428.3)	90.5	-9	(1,484.5)	7,493
-10	(475.9)	90.3	-10	(1,649.5)	7,498

Weighting Factor =

5.63%

Weighting Factor =

7.64%

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2020 - DECEMBER 2020

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,811.8	90.1	+10	3,332.3	7,250
+9	1,630.6	90.0	+9	2,999.1	7,267
+8	1,449.4	89.9	+8	2,665.8	7,285
+7	1,268.3	89.8	+7	2,332.6	7,302
+6	1,087.1	89.6	+6	1,999.4	7,319
+5	905.9	89.5	+5	1,666.1	7,337
+4	724.7	89.4	+4	1,332.9	7,354
+3	543.5	89.3	+3	999.7	7,372
+2	362.4	89.1	+2	666.5	7,389
+1	181.2	89.0	+1	333.2	7,407
					7,424
0	0.0	88.9	0	0.0	7,499
					7,574
-1	(62.2)	88.7	-1	(333.2)	7,592
-2	(124.3)	88.4	-2	(666.5)	7,609
-3	(186.5)	88.2	-3	(999.7)	7,627
-4	(248.7)	87.9	-4	(1,332.9)	7,644
-5	(310.9)	87.7	-5	(1,666.1)	7,661
-6	(373.0)	87.4	-6	(1,999.4)	7,679
-7	(435.2)	87.2	-7	(2,332.6)	7,696
-8	(497.4)	86.9	-8	(2,665.8)	7,714
-9	(559.5)	86.7	-9	(2,999.1)	7,731
-10	(621.7)	86.4	-10	(3,332.3)	7,749

Weighting Factor =

8.39%

Weighting Factor =

15.43%

**TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE**

EQUIVALENT AVAILABILITY (%)

<u>PLANT / UNIT</u>	<u>TARGET WEIGHTING FACTOR (%)</u>	<u>NORMALIZED WEIGHTING FACTOR</u>	<u>TARGET PERIOD JAN 20 - DEC 20</u>			<u>ACTUAL PERFORMANCE JAN 20 - DEC 20</u>		
			<u>POF</u>	<u>EUOF</u>	<u>EUOR</u>	<u>POF</u>	<u>EUOF</u>	<u>EUOR</u>
BIG BEND 4	1.40%	5.5%	21.8	22.8	29.1	37.1	25.1	39.9
POLK 1	3.1%	12.4%	8.5	16.0	17.5	5.3	24.7	26.1
POLK 2	6.8%	26.9%	12.6	2.5	2.9	2.8	7.7	8.0
BAYSIDE 1	5.6%	22.2%	6.6	1.7	1.9	7.7	2.9	3.1
BAYSIDE 2	<u>8.4%</u>	<u>33.0%</u>	<u>6.6</u>	<u>4.5</u>	<u>4.9</u>	<u>4.3</u>	<u>5.0</u>	<u>5.2</u>
GPIF SYSTEM	25.4%	100.0%	9.3	5.8	6.6	6.6	8.8	10.0
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)			<u>84.9</u>			<u>84.6</u>		
			<u>3 PERIOD AVERAGE</u>			<u>3 PERIOD AVERAGE</u>		
			<u>POF</u>	<u>EUOF</u>	<u>EUOR</u>	<u>EAF</u>		
			8.8	9.2	10.4	82.0		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

<u>PLANT / UNIT</u>	<u>TARGET WEIGHTING FACTOR (%)</u>	<u>NORMALIZED WEIGHTING FACTOR</u>	<u>TARGET HEAT RATE JAN 20 - DEC 20</u>	<u>ADJUSTED ACTUAL HEAT RATE JAN 20 - DEC 20</u>
BIG BEND 4	4.43%	5.9%	10,837	10,972
POLK 1	11.15%	14.9%	10,018	8,698
POLK 2	35.96%	48.2%	7,209	6,843
BAYSIDE 1	7.64%	10.2%	7,379	7,336
BAYSIDE 2	<u>15.43%</u>	<u>20.7%</u>	<u>7,499</u>	<u>7,324</u>
GPIF SYSTEM	74.6%	100.0%		
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			<u>7,922</u>	<u>7,515</u>

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2020 - DECEMBER 2020**

Points are calculated according to the formula:

$$GPIP = \sum_{i=1}^n [a_i(EAP_i) + e_i(AHRP_i)]$$

Where:

$GPIP$ = Generating performance incentive points

a_i = Percentage of total system fuel cost reduction attributed to maximum reasonably attainable equivalent availability of unit i during the period

e_i = Percentage of total system fuel cost reduction attributed to minimum reasonably attainable average heat rate of unit i during the period

EAP_i = Equivalent availability points awarded/deducted for unit i

$AHRP_i$ = Average heat rate points awarded/deducted for unit i

Weighting factors and point values are listed on page 4.

$$\begin{aligned} GPIP = & 3.15\% * (PK\ 1\ EAP) + 6.84\% * (PK\ 2\ EAP) + 5.63\% * (BAY\ 1\ EAP) \\ & + 8.39\% * (BAY\ 2\ EAP) + 11.15\% * (PK\ 1\ AHRP) + 35.96\% * (PK\ 2\ AHRP) \\ & + 7.64\% * (BAY\ 1\ AHRP) + 15.43\% * (BAY\ 2\ AHRP) + 4.43\% * (BB\ 4\ AHRP) \\ & + 1.40\% * (BB\ 4\ EAP) \end{aligned}$$

$$\begin{aligned} GPIP = & 3.15\% * -10.000 + 6.84\% * -10.000 + 5.63\% * -8.818 \\ & + 8.39\% * -1.618 + 11.15\% * 9.319 + 35.96\% * 9.141 \\ & + 7.64\% * 0.000 + 15.43\% * 5.742 + 4.43\% * -1.710 \\ & + 1.40\% * -7.439 \end{aligned}$$

$$\begin{aligned} GPIP = & -0.315 + -0.684 + -0.496 \\ & + -0.136 + 1.039 + 3.287 \\ & + 0.000 + 0.886 + -0.076 \\ & + -0.104 \end{aligned}$$

$$GPIP = \underline{3.401} \text{ POINTS}$$

REWARD/PENALTY dollar amounts of the Generating Performance Incentive Factor (GPIF) are determined directly from the table for the corresponding Generating Performance Points (GPIP) on page 2.

$$GPIF\ REWARD = \underline{\$3,673,726}$$

**EXHIBIT TO THE TESTIMONY OF
PATRICK A. BOKOR**

DOCKET NO. 20210001-EI

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2020 – DECEMBER 2020
TRUE-UP**

**DOCUMENT NO. 2
ACTUAL UNIT PERFORMANCE DATA**

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD	
BIG BEND 4		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. Equivalent Availability Factor (%)	EAF	0.9	0.0	0.0	0.0	0.2	31.6	29.5	40.3	55.8	32.6	79.5	44.0	35.7
2. Period Hours	PH	744.0	696.0	743.0	720.0	744.0	720.0	744.0	744.0	720.0	744.0	721.0	744.0	8,784.0
3. Service Hours	SH	629.2	0.0	0.0	0.0	1.4	580.8	738.6	425.2	602.7	366.4	664.4	407.8	4,416.5
4. Reserve Shutdown Hours	RSH	97.3	0.0	0.0	0.0	0.0	0.0	0.0	101.9	0.0	0.0	0.0	0.0	199.2
5. Unavailable Hours	UH	17.5	696.0	743.0	720.0	742.6	139.2	5.4	217.0	117.4	377.6	56.6	336.2	4,169.5
6. Planned Outage Hours	POH	17.5	696.0	743.0	720.0	659.8	0.0	0.0	0.0	0.0	377.6	47.3	0.0	3,262.2
7. Forced Outage Hours	FOH	0.0	0.0	0.0	0.0	0.0	2.0	5.4	0.0	11.3	0.0	9.3	336.2	364.2
8. Maintenance Outage Hours	MOH	0.0	0.0	0.0	0.0	82.8	137.2	0.0	217.0	106.1	0.0	0.0	0.0	543.1
9a. Partial Planned Outage Hours	PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	510.8	407.8	918.6
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	85.0	79.4
10a. Partial Forced Outage Hours	PFOH	509.5	0.0	0.0	0.0	0.0	471.0	738.7	527.0	0.0	347.8	0.0	0.0	2,594.0
10b. Load Reduction Partial Forced (MW)	LRPF	37.1	0.0	0.0	0.0	0.0	182.0	257.0	182.0	0.0	150.0	0.0	0.0	170.6
11a. Partial Maintenance Outage Hours	PMOH	0.0	0.0	0.0	0.0	0.0	138.2	87.0	0.0	0.0	0.0	0.0	0.0	225.2
11b. Load Reduction Partial Maintenance (MW)	LRPM	0.0	0.0	0.0	0.0	0.0	267.0	337.0	0.0	0.0	0.0	0.0	0.0	294.0
12. Net Summer Continuous Rating (MW)	NSC	347.0	347.0	347.0	347.0	347.0	422.0	422.0	422.0	422.0	422.0	422.0	422.0	390.8
13. Operating British Thermal Units (GBTU)	OPR BTU	1,977.2	0.0	0.0	0.0	0.0	1,230.0	1,592.4	1,018.3	1,477.8	830.0	2,180.3	1,213.0	11,518.9
14. Net Generation (MWH)	NETGEN	188,162.0	0.0	1.0	0.0	-2,245.0	106,678.0	141,282.0	87,762.0	134,685.0	84,214.0	197,333.0	116,234.0	1,054,106.0
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	10,508.0	0.0	0.0	0.0	0.0	11,530.0	11,271.0	11,603.0	10,972.0	9,856.0	11,049.0	10,436.0	10,927.6
16. Net Output Factor (%)	NOF	85.0	0.0	0.0	0.0	-455.6	52.9	45.3	48.9	53.0	54.5	70.4	66.0	60.8
17. Net Period Continuous Rating (MW)	NPC	352.0	352.0	352.0	347.0	347.0	422.0	422.0	422.0	422.0	422.0	422.0	432.0	392.8
18. Avg. Net Operating Heat Rate Equation		ANOHR = NOF (-5.6236) + 11,149												

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD	
POLK 1		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. Equivalent Availability Factor (%)	EAF	97.9	81.1	89.2	61.4	27.7	91.7	75.8	93.7	99.2	78.1	40.6	4.1	69.9
2. Period Hours	PH	744.0	696.0	743.0	720.0	744.0	720.0	744.0	744.0	720.0	744.0	721.0	744.0	8,784.0
3. Service Hours	SH	211.9	120.4	662.4	438.8	206.3	717.9	476.1	216.8	347.5	286.4	252.9	15.9	3,953.3
4. Reserve Shutdown Hours	RSH	516.8	444.0	0.0	44.0	0.0	0.0	174.8	527.3	366.4	294.6	39.3	14.7	2,421.9
5. Unavailable Hours	UH	15.3	131.6	80.6	237.2	537.7	2.1	93.1	0.0	6.2	163.0	427.8	713.5	2,408.1
6. Planned Outage Hours	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	359.8	108.0	467.8
7. Forced Outage Hours	FOH	1.6	10.7	0.0	154.1	537.7	2.1	0.0	0.0	6.2	150.8	0.0	605.5	1,468.7
8. Maintenance Outage Hours	MOH	13.7	120.9	80.6	83.1	0.0	0.0	93.1	0.0	0.0	12.3	68.0	0.0	471.7
9a. Partial Planned Outage Hours	PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10a. Partial Forced Outage Hours	PFOH	0.0	0.0	0.0	107.1	0.0	717.9	650.9	566.9	0.0	0.0	0.0	0.0	2,042.8
10b. Load Reduction Partial Forced (MW)	LRPF	0.0	0.0	0.0	90.0	0.0	18.9	28.0	13.3	0.0	0.0	0.0	0.0	24.0
11a. Partial Maintenance Outage Hours	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11b. Load Reduction Partial Maintenance (MW)	LRPM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	119.8	229.6	0.0	0.0
12. Net Summer Continuous Rating (MW)	NSC	210.0	210.0	210.0	210.0	210.0	210.0	210.0	210.0	202.0	202.0	202.0	202.0	207.3
13. Operating British Thermal Units (GBTU)	OPR BTU	256.3	157.0	877.3	555.1	298.1	1,068.7	613.0	256.9	440.2	338.7	322.1	19.5	5,202.9
14. Net Generation (MWH)	NETGEN	30,426.0	15,360.0	101,937.0	62,777.0	33,685.0	130,490.0	68,825.0	27,805.0	46,082.0	35,386.0	34,985.0	-648.0	587,110.0
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	8,424.0	10,218.0	8,606.0	8,843.0	8,849.0	8,188.0	11,271.0	11,603.0	9,553.0	9,572.0	9,206.0	0.0	8,861.8
16. Net Output Factor (%)	NOF	59.3	52.7	63.4	60.9	69.0	77.4	68.8	61.1	65.7	61.2	68.5	-22.7	70.3
17. Net Period Continuous Rating (MW)	NPC	230.0	230.0	230.0	210.0	210.0	210.0	210.0	210.0	210.0	202.0	202.0	180.0	211.2
18. Avg. Net Operating Heat Rate Equation		ANOHR = NOF (-7.778) + 10,842												

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD	
POLK 2		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. Equivalent Availability Factor (%)	EAF	99.4	92.2	99.3	96.1	91.4	82.8	95.5	92.9	72.0	64.2	62.3	81.3	89.5
2. Period Hours	PH	744.0	696.0	743.0	720.0	744.0	720.0	744.0	744.0	720.0	744.0	721.0	744.0	8,784.0
3. Service Hours	SH	741.6	675.1	733.0	714.9	709.0	597.6	732.1	736.4	607.0	590.0	589.6	664.3	8,090.6
4. Reserve Shutdown Hours	RSH	0.0	0.0	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5
5. Unavailable Hours	UH	2.4	20.9	5.5	5.1	35.0	122.4	11.9	7.6	113.0	154.0	131.4	79.7	688.9
6. Planned Outage Hours	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.8	101.8	15.8	82.9	38.7	246.0
7. Forced Outage Hours	FOH	0.1	7.7	5.5	0.1	0.0	122.4	0.3	0.8	5.2	130.9	48.5	28.7	350.2
8. Maintenance Outage Hours	MOH	2.3	13.2	0.0	5.0	35.0	0.0	11.6	0.0	6.1	7.2	0.0	12.2	92.6
9a. Partial Planned Outage Hours	PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10a. Partial Forced Outage Hours	PFOH	9.2	14.3	0.0	33.6	0.4	6.0	43.0	134.5	39.1	349.7	172.6	74.8	877.2
10b. Load Reduction Partial Forced (MW)	LRPF	166.1	179.5	0.0	338.2	126.2	241.0	133.6	120.8	55.3	136.5	138.2	182.1	144.0
11a. Partial Maintenance Outage Hours	PMOH	0.0	106.6	0.0	15.4	107.7	0.0	35.8	40.0	311.6	33.6	176.8	103.2	930.7
11b. Load Reduction Partial Maintenance (MW)	LRPM	0.0	125.0	0.0	125.0	125.0	0.0	119.8	119.8	123.8	119.8	229.6	143.8	145.9
12. Net Summer Continuous Rating (MW)	NSC	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0
13. Operating British Thermal Units (GBTU)	OPR BTU	4,418.6	4,119.3	4,573.1	4,030.8	3,911.8	3,627.4	3,718.0	3,677.7	2,648.7	2,516.2	2,624.7	3,618.2	43,484.4
14. Net Generation (MWH)	NETGEN	636,822.0	593,139.0	665,332.0	581,812.0	559,597.0	514,715.0	521,798.0	518,105.0	373,027.0	291,570.0	366,035.0	512,193.0	6,134,145.0
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	6,938.0	6,945.0	6,873.0	6,928.0	6,990.0	7,048.0	7,125.0	7,098.0	7,100.0	7,307.0	7,171.0	7,064.0	7,088.9
16. Net Output Factor (%)	NOF	71.3	71.0	75.5	76.2	70.9	78.3	66.1	65.6	49.0	44.8	48.1	57.4	67.5
17. Net Period Continuous Rating (MW)	NPC	1,200.0	1,200.0	1,200.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,061.0	1,200.0	1,107.3
18. Avg. Net Operating Heat Rate Equation		ANOHR = NOF (-53.862) + 11,266												

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 1		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. Equivalent Availability Factor (%)	EAF	99.1	88.3	48.0	99.9	97.3	98.7	91.4	98.6	98.2	99.1	96.7	55.7	89.5
2. Period Hours	PH	744.0	696.0	743.0	720.0	744.0	720.0	744.0	744.0	720.0	744.0	721.0	744.0	8,784.0
3. Service Hours	SH	739.2	480.7	348.7	717.4	730.6	713.9	681.0	736.9	711.4	739.7	705.0	1.3	7,305.8
4. Reserve Shutdown Hours	RSH	0.0	142.0	10.1	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	413.2	567.0
5. Unavailable Hours	UH	4.8	73.3	384.2	0.9	13.4	6.1	63.0	7.1	8.6	4.3	16.0	329.5	911.2
6. Planned Outage Hours	POH	0.0	57.5	275.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.8	329.5	673.8
7. Forced Outage Hours	FOH	1.2	0.0	109.2	0.9	13.4	0.0	0.0	7.1	0.6	0.0	0.0	0.0	132.4
8. Maintenance Outage Hours	MOH	3.6	15.8	0.0	0.0	0.0	6.1	63.0	0.0	8.0	4.3	4.2	0.0	105.0
9a. Partial Planned Outage Hours	PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10a. Partial Forced Outage Hours	PFOH	2.1	0.0	7.6	0.0	16.8	0.0	3.3	10.6	0.9	0.0	0.0	0.0	41.3
10b. Load Reduction Partial Forced (MW)	LRPF	69.4	0.0	79.0	0.0	94.1	0.0	79.1	79.0	79.1	0.0	0.0	0.0	84.7
11a. Partial Maintenance Outage Hours	PMOH	4.8	23.9	0.0	0.0	0.0	9.1	0.0	0.0	11.9	6.4	16.5	0.2	72.9
11b. Load Reduction Partial Maintenance (MW)	LRPM	78.0	80.4	0.0	0.0	0.0	79.0	0.0	0.0	79.0	79.0	114.1	258.6	87.9
12. Net Summer Continuous Rating (MW)	NSC	701.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0
13. Operating British Thermal Units (GBTU)	OPR BTU	1,875.0	1,493.5	1,050.7	2,025.6	2,499.8	2,267.2	2,404.8	2,912.4	2,241.8	2,354.4	2,180.4	0.0	23,305.7
14. Net Generation (MWH)	NETGEN	248,230.8	203,342.1	140,773.6	274,428.4	339,658.8	290,222.0	323,875.6	395,805.8	302,915.5	319,377.5	305,529.4	0.0	3,144,159.5
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	7,554.0	7,345.0	7,464.0	7,381.0	7,360.0	7,812.0	7,425.0	7,358.0	7,401.0	7,401.0	7,136.0	0.0	7,412.4
16. Net Output Factor (%)	NOF	42.1	53.4	50.8	54.6	65.1	57.5	66.3	75.9	60.0	61.2	60.5	0.0	58.8
17. Net Period Continuous Rating (MW)	NPC	792.0	792.0	792.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	792.0	731.3
18. Avg. Net Operating Heat Rate Equation	ANOHR = NOF (-2.852) + 7,630													

ORIGINAL SHEET NO. 8.401.19A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

PLANT/UNIT		MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD	
BAYSIDE 2		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. Equivalent Availability Factor (%)	EAF	71.3	95.4	99.9	98.5	83.8	97.8	95.3	91.9	99.2	99.6	46.3	99.0	90.6
2. Period Hours	PH	744.0	696.0	743.0	720.0	744.0	720.0	744.0	744.0	720.0	744.0	721.0	744.0	8,784.0
3. Service Hours	SH	85.2	672.4	742.3	712.7	663.8	709.4	720.5	744.0	715.9	742.0	339.7	738.6	7,586.5
4. Reserve Shutdown Hours	RSH	448.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	408.5
5. Unavailable Hours	UH	210.0	23.6	0.7	7.3	80.2	10.6	23.5	40.3	4.1	2.0	381.3	5.4	789.0
6. Planned Outage Hours	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	381.3	0.0	381.3
7. Forced Outage Hours	FOH	3.5	6.5	0.0	7.3	26.2	3.9	11.1	0.0	0.0	0.0	0.0	1.7	60.2
8. Maintenance Outage Hours	MOH	206.5	17.1	0.7	0.0	54.0	6.7	12.3	40.3	4.1	2.0	0.0	3.7	347.4
9a. Partial Planned Outage Hours	PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9b. Load Reduction Partial Planned (MW)	LRPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10a. Partial Forced Outage Hours	PFOH	4.8	11.2	0.0	14.2	47.9	7.7	21.8	0.0	0.0	0.0	0.0	2.9	110.5
10b. Load Reduction Partial Forced (MW)	LRPF	77.1	77.0	0.0	77.0	89.4	67.0	77.0	0.0	0.0	0.0	0.0	77.1	81.7
11a. Partial Maintenance Outage Hours	PMOH	9.6	20.2	1.2	0.0	105.6	13.1	24.1	78.8	8.0	3.9	10.4	6.4	281.3
11b. Load Reduction Partial Maintenance (MW)	LRPM	77.0	92.4	77.4	0.0	77.0	77.0	77.0	77.0	77.0	77.0	154.8	77.1	81.0
12. Net Summer Continuous Rating (MW)	NSC	929.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0
13. Operating British Thermal Units (GBTU)	OPR BTU	189.5	2,657.5	3,038.4	3,056.0	2,699.8	3,308.5	3,631.2	3,462.6	3,138.8	2,928.7	1,058.7	3,370.3	32,540.1
14. Net Generation (MWH)	NETGEN	22,308.2	357,443.8	406,847.3	417,285.6	366,298.4	431,349.1	495,327.5	471,829.2	428,814.5	398,819.3	138,818.6	463,595.0	4,398,736.5
15. Avg. Net Operating Heat Rate (BTU/KWH)	ANOHR	8,496.0	7,435.0	7,468.0	7,324.0	7,371.0	7,670.0	7,331.0	7,339.0	7,320.0	7,343.0	7,626.0	7,270.0	7,397.6
16. Net Output Factor (%)	NOF	25.0	49.1	52.2	62.4	53.0	64.5	71.7	68.3	64.1	57.7	42.9	59.5	59.8
17. Net Period Continuous Rating (MW)	NPC	1,047.0	1,047.0	1,047.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	1,047.0	968.3
18. Avg. Net Operating Heat Rate Equation		ANOHR = NOF (-6.673) + 7,965												

DOCKET NO. 20210001-EI GPIF
2022 PROJECTION FILING
EXHIBIT NO. PAB-2
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY

OF

PATRICK A. BOKOR

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2022 – DECEMBER 2022

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2022 - DECEMBER 2022
TARGETS
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**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2022 - DECEMBER 2022**

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) (\$000)	GENERATING PERFORMANCE INCENTIVE FACTOR (\$000)
+10	31,877.1	13,796.2
+9	28,689.4	12,416.6
+8	25,501.7	11,037.0
+7	22,314.0	9,657.4
+6	19,126.3	8,277.7
+5	15,938.6	6,898.1
+4	12,750.8	5,518.5
+3	9,563.1	4,138.9
+2	6,375.4	2,759.2
+1	3,187.7	1,379.6
0	0.0	0.0
-1	(3,159.1)	(1,379.6)
-2	(6,318.1)	(2,759.2)
-3	(9,477.2)	(4,138.9)
-4	(12,636.2)	(5,518.5)
-5	(15,795.3)	(6,898.1)
-6	(18,954.4)	(8,277.7)
-7	(22,113.4)	(9,657.4)
-8	(25,272.5)	(11,037.0)
-9	(28,431.5)	(12,416.6)
-10	(31,590.6)	(13,796.2)

**TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2022 - DECEMBER 2022**

Line 1	Beginning of period balance of common equity:	\$	4,003,519,446	
	End of month common equity:			
Line 2	Month of January	2022	\$	4,021,748,185
Line 3	Month of February	2022	\$	4,056,100,618
Line 4	Month of March	2022	\$	4,090,746,477
Line 5	Month of April	2022	\$	4,038,461,239
Line 6	Month of May	2022	\$	4,072,956,429
Line 7	Month of June	2022	\$	4,107,746,265
Line 8	Month of July	2022	\$	4,125,833,476
Line 9	Month of August	2022	\$	4,161,074,971
Line 10	Month of September	2022	\$	4,196,617,486
Line 11	Month of October	2022	\$	4,143,592,373
Line 12	Month of November	2022	\$	4,178,985,558
Line 13	Month of December	2022	\$	4,214,681,059
Line 14	(Summation of line 1 through line 13 divided by 13)		\$	4,108,620,276
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			74.45%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)	\$		13,796,217
Line 18	Jurisdictional Sales			19,807,340 MWH
Line 19	Total Sales			19,807,340 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			100.00%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)	\$		13,796,217
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)	\$		15,938,559
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)	\$		13,796,217

Note: Line 22 and 23 are as approved by Commission order PSC-13-0665-FOF-EI dated 12/18/13 effective 1/1/14.

**TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2022 - DECEMBER 2022**

EQUIVALENT AVAILABILITY

<u>PLANT / UNIT</u>	<u>WEIGHTING FACTOR (%)</u>	<u>EAF TARGET (%)</u>	<u>EAF RANGE</u>		<u>MAX. FUEL SAVINGS (\$000)</u>	<u>MAX. FUEL LOSS (\$000)</u>
			<u>MAX. (%)</u>	<u>MIN. (%)</u>		
BIG BEND 4	4.38%	71.7	75.6	64.0	1,396.6	(1,511.6)
POLK 1	0.50%	87.7	89.9	83.4	160.0	(226.0)
POLK 2	5.01%	89.3	90.3	87.5	1,595.5	(1,422.5)
BAYSIDE 1	1.86%	77.4	78.9	74.4	592.7	(66.4)
BAYSIDE 2	1.44%	92.7	93.6	91.0	458.8	(690.7)
GPIF SYSTEM	13.19%					

AVERAGE NET OPERATING HEAT RATE

<u>PLANT / UNIT</u>	<u>WEIGHTING FACTOR (%)</u>	<u>ANOHR Btu/kwh</u>	<u>TARGET NOF</u>	<u>ANOHR RANGE</u>		<u>MAX. FUEL SAVINGS (\$000)</u>	<u>MAX. FUEL LOSS (\$000)</u>
				<u>MIN.</u>	<u>MAX.</u>		
BIG BEND 4	11.18%	10,726	47.8	9,624	11,828	3,563.3	(3,563.3)
POLK 1	6.62%	8,855	79.1	7,271	10,440	2,111.3	(2,111.3)
POLK 2	52.47%	6,841	76.0	5,918	7,764	16,725.7	(16,725.7)
BAYSIDE 1	4.45%	7,339	65.3	7,168	7,510	1,417.9	(1,417.9)
BAYSIDE 2	12.09%	7,695	47.4	7,419	7,971	3,855.2	(3,855.2)
GPIF SYSTEM	86.81%						

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 22 - DEC 22			ACTUAL PERFORMANCE JAN 20 - DEC 20			ACTUAL PERFORMANCE JAN 19 - DEC 19			ACTUAL PERFORMANCE JAN 18 - DEC 18		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
BIG BEND 4	4.38%	33.2%	12.1	16.2	18.4	39.1	24.8	40.6	16.5	28.0	39.8	19.1	20.6	26.6
POLK 1	0.50%	3.8%	1.9	10.3	10.5	5.3	22.4	33.3	6.7	14.9	22.8	28.1	10.7	16.3
POLK 2	5.01%	38.0%	7.9	2.7	2.9	3.2	10.4	10.1	4.5	3.7	3.8	2.0	3.3	3.2
BAYSIDE 1	1.86%	14.1%	20.3	2.4	3.0	7.8	3.4	3.9	11.1	6.7	7.4	5.3	1.6	1.7
BAYSIDE 2	1.44%	10.9%	3.8	3.4	3.6	4.3	5.9	6.3	12.8	4.0	4.5	19.6	2.5	3.1
GPIF SYSTEM	13.19%	100.0%	10.4	7.5	8.5	16.0	14.1	19.8	10.4	12.6	17.1	11.1	9.0	11.3
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)			82.1			69.9			77.0			79.9		
			3 PERIOD AVERAGE			3 PERIOD AVERAGE								
			POF	EUOF	EUOR	EA								
			12.5	11.9	16.0	75.6								

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 22 - DEC 22		ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 20 - DEC 20		ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 19 - DEC 19		ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 18 - DEC 18	
BIG BEND 4	11.18%	12.9%	10,726		11,017		10,986		10,959	
POLK 1	6.62%	7.6%	8,855		8,774		8,757		10,367	
POLK 2	52.47%	60.4%	6,841		6,640		7,458		6,983	
BAYSIDE 1	4.45%	5.1%	7,339		7,363		7,361		7,378	
BAYSIDE 2	12.09%	13.9%	7,695		7,619		7,726		7,594	
GPIF SYSTEM	86.81%	100.0%								
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			7,639		7,540		8,044		7,859	

**TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2022 - DECEMBER 2022
PRODUCTION COSTING SIMULATION
FUEL COST (\$000)**

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA ₃ BIG BEND 4	487,019.89	485,623.26	1,396.63	4.38%
EA ₁ POLK 1	487,019.89	486,859.87	160.02	0.50%
EA ₂ POLK 2	487,019.89	485,424.37	1,595.52	5.01%
EA ₃ BAYSIDE 1	487,019.89	486,427.17	592.72	1.86%
EA ₄ BAYSIDE 2	487,019.89	486,561.10	458.79	1.44%
AVERAGE HEAT RATE				
AHR ₃ BIG BEND 4	487,019.89	483,456.56	3,563.33	11.18%
AHR ₁ POLK 1	487,019.89	484,908.57	2,111.32	6.62%
AHR ₂ POLK 2	487,019.89	470,294.19	16,725.70	52.47%
AHR ₃ BAYSIDE 1	487,019.89	485,601.97	1,417.92	4.45%
AHR ₄ BAYSIDE 2	487,019.89	483,164.72	3,855.17	12.09%
TOTAL SAVINGS			31,877.12	100.00%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other units performance indicators at target.

(3) Expressed in replacement energy cost.

GPIF TARGET AND RANGE SUMMARY

JANUARY 2022 - DECEMBER 2022

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,396.6	75.6	+10	3,563.3	9,624
+9	1,257.0	78.0	+9	3,207.0	9,727
+8	1,117.3	80.5	+8	2,850.7	9,829
+7	977.6	82.9	+7	2,494.3	9,932
+6	838.0	85.3	+6	2,138.0	10,035
+5	698.3	87.8	+5	1,781.7	10,137
+4	558.7	90.2	+4	1,425.3	10,240
+3	419.0	92.7	+3	1,069.0	10,343
+2	279.3	95.1	+2	712.7	10,446
+1	139.7	97.6	+1	356.3	10,548
					10,651
0	0.0	100.0	0	0.0	10,726
					10,801
-1	(151.2)	96.4	-1	(356.3)	10,904
-2	(302.3)	92.8	-2	(712.7)	11,007
-3	(453.5)	89.2	-3	(1,069.0)	11,109
-4	(604.6)	85.6	-4	(1,425.3)	11,212
-5	(755.8)	82.0	-5	(1,781.7)	11,315
-6	(906.9)	78.4	-6	(2,138.0)	11,418
-7	(1,058.1)	74.8	-7	(2,494.3)	11,520
-8	(1,209.3)	71.2	-8	(2,850.7)	11,623
-9	(1,360.4)	67.6	-9	(3,207.0)	11,726
-10	(1,511.6)	64.0	-10	(3,563.3)	11,828
Weighting Factor =		4.38%	Weighting Factor =		11.18%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

JANUARY 2022 - DECEMBER 2022

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	160.0	89.9	+10	2,111.3	7,271
+9	144.0	89.7	+9	1,900.2	7,422
+8	128.0	89.5	+8	1,689.1	7,573
+7	112.0	89.3	+7	1,477.9	7,724
+6	96.0	89.0	+6	1,266.8	7,875
+5	80.0	88.8	+5	1,055.7	8,026
+4	64.0	88.6	+4	844.5	8,177
+3	48.0	88.4	+3	633.4	8,327
+2	32.0	88.2	+2	422.3	8,478
+1	16.0	88.0	+1	211.1	8,629
					8,780
0	0.0	87.7	0	0.0	8,855
					8,930
-1	(22.6)	87.3	-1	(211.1)	9,081
-2	(45.2)	86.9	-2	(422.3)	9,232
-3	(67.8)	86.4	-3	(633.4)	9,383
-4	(90.4)	86.0	-4	(844.5)	9,534
-5	(113.0)	85.6	-5	(1,055.7)	9,685
-6	(135.6)	85.1	-6	(1,266.8)	9,836
-7	(158.2)	84.7	-7	(1,477.9)	9,987
-8	(180.8)	84.3	-8	(1,689.1)	10,138
-9	(203.4)	83.8	-9	(1,900.2)	10,289
-10	(226.0)	83.4	-10	(2,111.3)	10,440

Weighting Factor =

0.50%

Weighting Factor =

6.62%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

JANUARY 2022 - DECEMBER 2022

POLK 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,595.5	90.3	+10	16,725.7	5,918
+9	1,436.0	90.2	+9	15,053.1	6,003
+8	1,276.4	90.1	+8	13,380.6	6,088
+7	1,116.9	90.0	+7	11,708.0	6,173
+6	957.3	89.9	+6	10,035.4	6,257
+5	797.8	89.8	+5	8,362.9	6,342
+4	638.2	89.7	+4	6,690.3	6,427
+3	478.7	89.6	+3	5,017.7	6,512
+2	319.1	89.5	+2	3,345.1	6,596
+1	159.6	89.4	+1	1,672.6	6,681
					6,766
0	0.0	89.3	0	0.0	6,841
					6,916
-1	(142.3)	89.2	-1	(1,672.6)	7,001
-2	(284.5)	89.0	-2	(3,345.1)	7,086
-3	(426.8)	88.8	-3	(5,017.7)	7,170
-4	(569.0)	88.6	-4	(6,690.3)	7,255
-5	(711.3)	88.4	-5	(8,362.9)	7,340
-6	(853.5)	88.2	-6	(10,035.4)	7,425
-7	(995.8)	88.0	-7	(11,708.0)	7,510
-8	(1,138.0)	87.8	-8	(13,380.6)	7,594
-9	(1,280.3)	87.6	-9	(15,053.1)	7,679
-10	(1,422.5)	87.5	-10	(16,725.7)	7,764

Weighting Factor =

5.01%

Weighting Factor =

52.47%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

JANUARY 2022 - DECEMBER 2022

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	592.7	78.9	+10	1,417.9	7,168
+9	533.4	78.7	+9	1,276.1	7,178
+8	474.2	78.6	+8	1,134.3	7,188
+7	414.9	78.4	+7	992.5	7,197
+6	355.6	78.3	+6	850.8	7,207
+5	296.4	78.1	+5	709.0	7,216
+4	237.1	78.0	+4	567.2	7,226
+3	177.8	77.8	+3	425.4	7,236
+2	118.5	77.7	+2	283.6	7,245
+1	59.3	77.5	+1	141.8	7,255
					7,264
0	0.0	77.4	0	0.0	7,339
					7,414
-1	(6.6)	77.1	-1	(141.8)	7,424
-2	(13.3)	76.8	-2	(283.6)	7,434
-3	(19.9)	76.5	-3	(425.4)	7,443
-4	(26.5)	76.2	-4	(567.2)	7,453
-5	(33.2)	75.9	-5	(709.0)	7,462
-6	(39.8)	75.6	-6	(850.8)	7,472
-7	(46.5)	75.3	-7	(992.5)	7,482
-8	(53.1)	75.0	-8	(1,134.3)	7,491
-9	(59.7)	74.7	-9	(1,276.1)	7,501
-10	(66.4)	74.4	-10	(1,417.9)	7,510

Weighting Factor =

1.86%

Weighting Factor =

4.45%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

JANUARY 2022 - DECEMBER 2022

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) (\$000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	458.8	93.6	+10	3,855.2	7,419
+9	412.9	93.5	+9	3,469.7	7,439
+8	367.0	93.4	+8	3,084.1	7,459
+7	321.2	93.4	+7	2,698.6	7,479
+6	275.3	93.3	+6	2,313.1	7,499
+5	229.4	93.2	+5	1,927.6	7,519
+4	183.5	93.1	+4	1,542.1	7,540
+3	137.6	93.0	+3	1,156.6	7,560
+2	91.8	92.9	+2	771.0	7,580
+1	45.9	92.8	+1	385.5	7,600
					7,620
0	0.0	92.7	0	0.0	7,695
					7,770
-1	(69.1)	92.6	-1	(385.5)	7,790
-2	(138.1)	92.4	-2	(771.0)	7,810
-3	(207.2)	92.2	-3	(1,156.6)	7,830
-4	(276.3)	92.0	-4	(1,542.1)	7,850
-5	(345.3)	91.9	-5	(1,927.6)	7,870
-6	(414.4)	91.7	-6	(2,313.1)	7,891
-7	(483.5)	91.5	-7	(2,698.6)	7,911
-8	(552.5)	91.3	-8	(3,084.1)	7,931
-9	(621.6)	91.2	-9	(3,469.7)	7,951
-10	(690.7)	91.0	-10	(3,855.2)	7,971

Weighting Factor =

1.44%

Weighting Factor =

12.09%

ORIGINAL SHEET NO. 8.401.20E

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2022 - DECEMBER 2022

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22						2022
BIG BEND 4																		
1. EAF (%)	81.6	81.6	81.6	43.5	81.6	81.6	81.6	81.6	81.6	7.9	76.1	81.6						71.7
2. POF	0.0	0.0	0.0	46.7	0.0	0.0	0.0	0.0	0.0	90.3	6.7	0.0						12.1
3. EUOF	18.4	18.4	18.4	9.8	18.4	18.4	18.4	18.4	18.4	1.8	17.2	18.4						16.2
4. EUOR	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4						18.4
5. PH	744	672	744	720	744	720	744	744	720	744	720	744						8,760
6. SH	673	608	542	477	673	651	673	673	651	66	608	673						6,968
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0						0
8. UH	71	64	202	243	71	69	71	71	69	678	112	71						1,792
9. POH	0	0	0	336	0	0	0	0	0	672	48	0						1,056
10. EFOH	65	59	65	34	65	63	65	65	63	6	59	65						673
11. EMOH	72	65	72	37	72	70	72	72	70	7	65	72						747
12. OPER BTU (GBTU)	1,470	1,266	1,123	983	1,416	1,430	1,509	1,577	1,613	167	1,251	1,398						15,204
13. NET GEN (MWH)	137,010	117,830	104,500	91,550	131,920	133,370	140,840	147,300	150,960	15,670	116,460	130,100						1,417,510
14. ANOHR (Btu/kwh)	10,730	10,743	10,745	10,740	10,734	10,722	10,716	10,703	10,685	10,678	10,740	10,744						10,726
15. NOF (%)	47.1	44.9	44.6	45.5	46.4	48.5	49.6	51.9	55.0	56.3	45.4	44.7						47.8
16. NPC (MW)	432	432	432	422	422	422	422	422	422	422	422	432						425
17. ANOHR EQUATION	ANOHR = NOF(-5.752) + 11,001																	

TAMPA ELECTRIC COMPANY
ESTIMATED UNIT PERFORMANCE DATA
JANUARY 2022 - DECEMBER 2022

PLANT/UNIT	MONTH OF: Jan-22	MONTH OF: Feb-22	MONTH OF: Mar-22	MONTH OF: Apr-22	MONTH OF: May-22	MONTH OF: Jun-22	MONTH OF: Jul-22	MONTH OF: Aug-22	MONTH OF: Sep-22	MONTH OF: Oct-22	MONTH OF: Nov-22	MONTH OF: Dec-22	PERIOD 2022
POLK 1													
1. EAF (%)	89.5	89.5	89.5	89.5	69.3	89.5	89.5	89.5	89.5	89.5	89.5	89.5	87.7
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
3. EUOF	10.5	10.5	10.5	10.5	8.2	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.3
4. EUOR	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	64	32	114	185	154	276	406	334	444	501	272	144	2,926
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	680	640	630	535	590	444	338	410	276	243	448	600	5,834
9. POH	0	0	0	0	168	0	0	0	0	0	0	0	168
10. EFOH	0	0	0	0	0	0	0	0	0	0	0	0	1
11. EMOH	78	71	78	76	61	76	78	78	76	78	76	78	905
12. OPER BTU (GBTU)	97	48	168	271	230	421	615	496	691	781	395	213	4,438
13. NET GEN (MWH)	10,860	5,340	18,740	30,630	26,020	47,770	69,780	56,150	78,730	88,920	44,490	23,720	501,150
14. ANOHR (Btu/kwh)	8,930	8,947	8,962	8,858	8,836	8,808	8,816	8,841	8,780	8,778	8,872	8,960	8,855
15. NOF (%)	73.8	72.6	71.5	78.8	80.5	82.4	81.8	80.1	84.4	84.5	77.9	71.6	79.1
16. NPC (MW)	230	230	230	210	210	210	210	210	210	210	210	230	217
17. ANOHR EQUATION	ANOHR = NOF(-14.091) + 9,969												

TAMPA ELECTRIC COMPANY
ESTIMATED UNIT PERFORMANCE DATA
JANUARY 2022 - DECEMBER 2022

PLANT/UNIT	MONTH OF: Jan-22	MONTH OF: Feb-22	MONTH OF: Mar-22	MONTH OF: Apr-22	MONTH OF: May-22	MONTH OF: Jun-22	MONTH OF: Jul-22	MONTH OF: Aug-22	MONTH OF: Sep-22	MONTH OF: Oct-22	MONTH OF: Nov-22	MONTH OF: Dec-22	PERIOD
POLK 2													2022
1. EAF (%)	97.1	97.1	21.9	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	81.4	89.3
2. POF	0.0	0.0	77.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	7.9
3. EUOF	2.9	2.9	0.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.5	2.7
4. EUOR	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	719	650	593	703	726	703	726	726	703	726	703	596	8,274
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	25	22	151	17	18	17	18	18	17	18	17	148	486
9. POH	0	0	576	0	0	0	0	0	0	0	0	120	696
10. EFOH	12	11	3	12	12	12	12	12	12	12	12	10	133
11. EMOH	10	9	2	9	10	9	10	10	9	10	9	8	105
12. OPER BTU (GBTU)	4,695	4,226	3,737	3,758	4,269	4,304	4,429	4,402	4,192	4,220	2,349	1,971	47,610
13. NET GEN (MWH)	706,640	634,120	549,650	539,980	651,230	679,030	696,250	688,390	646,460	638,210	290,900	238,550	6,959,410
14. ANOHR (Btu/kwh)	6,644	6,664	6,799	6,960	6,555	6,339	6,361	6,395	6,485	6,612	8,074	8,262	6,841
15. NOF (%)	81.9	81.3	77.2	72.4	84.5	91.0	90.4	89.4	86.7	82.9	39.0	33.4	76.0
16. NPC (MW)	1,200	1,200	1,200	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,200	1,107
17. ANOHR EQUATION	ANOHR = NOF(-33.331) + 9.373												

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2022 - DECEMBER 2022

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22				
BAYSIDE 1																2022
1. EAF (%)	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	29.1	0.0	25.9	97.0	77.4			
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	100.0	73.3	0.0	20.3			
3. EUOF	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.9	0.0	0.8	3.0	2.4			
4. EUOR	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.0	3.0	3.0	3.0			
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760			
6. SH	687	645	718	694	714	694	717	718	209	0	76	676	6,548			
7. RSH	35	7	4	5	8	5	5	4	1	0	110	46	230			
8. UH	22	20	22	21	22	21	22	22	510	744	534	22	1,982			
9. POH	0	0	0	0	0	0	0	0	504	744	528	0	1,776			
10. EFOH	15	14	15	15	15	15	15	15	4	0	4	15	145			
11. EMOH	7	6	7	6	7	6	7	7	2	0	2	7	61			
12. OPER BTU (GBTU)	2,242	1,961	2,540	2,554	2,741	2,913	3,031	2,796	756	0	114	1,226	22,953			
13. NET GEN (MWH)	302,630	263,750	344,540	350,150	377,110	403,700	420,270	385,060	103,560	0	14,950	161,680	3,127,400			
14. ANOHR (Btu/kwh)	7,407	7,435	7,372	7,293	7,269	7,216	7,212	7,261	7,302	0	7,599	7,584	7,339			
15. NOF (%)	55.6	51.6	60.6	72.0	75.3	83.0	83.6	76.5	70.7	0.0	28.1	30.2	65.3			
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731			
17. ANOHR EQUATION	ANOHR = NOF(-6.975) + 7.795															

TAMPA ELECTRIC COMPANY
ESTIMATED UNIT PERFORMANCE DATA
JANUARY 2022 - DECEMBER 2022

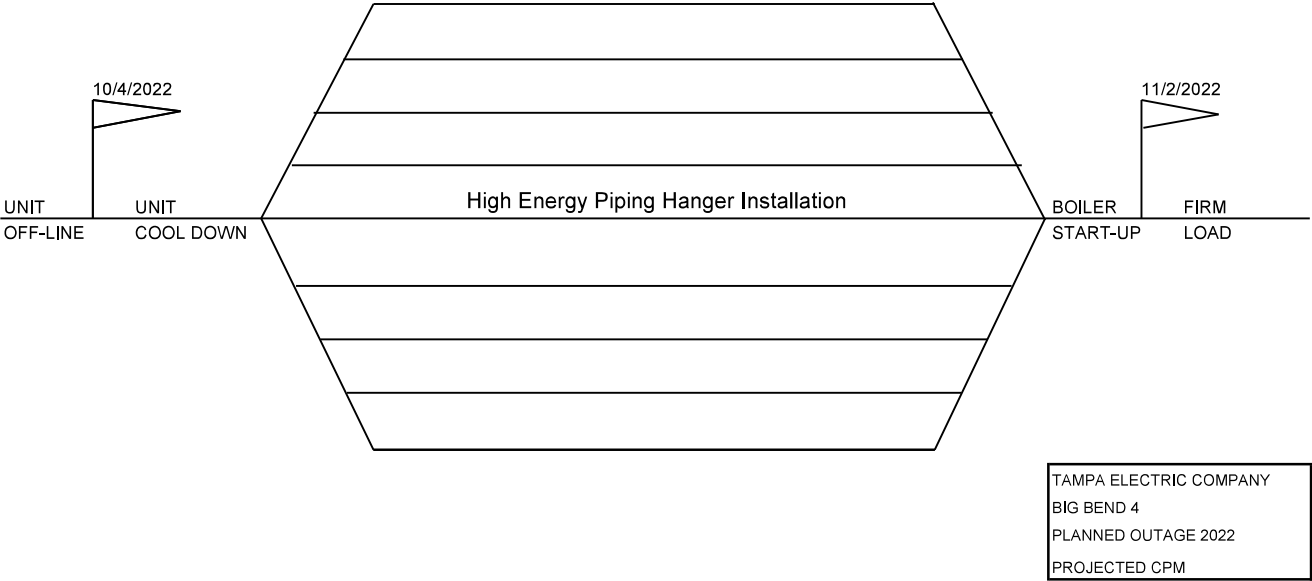
PLANT/UNIT	MONTH OF: Jan-22	MONTH OF: Feb-22	MONTH OF: Mar-22	MONTH OF: Apr-22	MONTH OF: May-22	MONTH OF: Jun-22	MONTH OF: Jul-22	MONTH OF: Aug-22	MONTH OF: Sep-22	MONTH OF: Oct-22	MONTH OF: Nov-22	MONTH OF: Dec-22	PERIOD
BAYSIDE 2													2022
1. EAF (%)	96.4	96.4	96.4	96.4	96.4	96.4	96.4	96.4	96.4	96.4	90.0	59.1	92.7
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.7	38.7	3.8
3. EUOF	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.3	2.2	3.4
4. EUOR	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	669	623	700	691	716	694	717	716	694	717	514	172	7,623
7. RSH	49	25	18	3	2	0	1	2	0	1	134	268	502
8. UH	26	24	26	26	26	26	26	26	26	26	72	304	635
9. POH	0	0	0	0	0	0	0	0	0	0	48	288	336
10. EFOH	6	6	6	6	6	6	6	6	6	6	6	4	70
11. EMOH	20	18	20	20	20	20	20	20	20	20	18	12	229
12. OPER BTU (GBTU)	1,542	1,328	2,176	2,371	2,735	3,086	3,165	2,862	2,946	3,024	889	424	26,920
13. NET GEN (MWH)	190,460	163,160	275,920	308,720	361,910	420,290	430,350	381,650	397,300	407,300	108,630	52,670	3,498,360
14. ANOHR (Btu/kwh)	8,094	8,137	7,888	7,681	7,557	7,344	7,355	7,498	7,414	7,423	8,182	8,054	7,695
15. NOF (%)	27.2	25.0	37.6	48.1	54.4	65.2	64.6	57.4	61.6	61.1	22.7	29.2	47.4
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968
17. ANOHR EQUATION	ANOHR = NOF(-19.753) + 8.631												

**TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2022 - DECEMBER 2022**

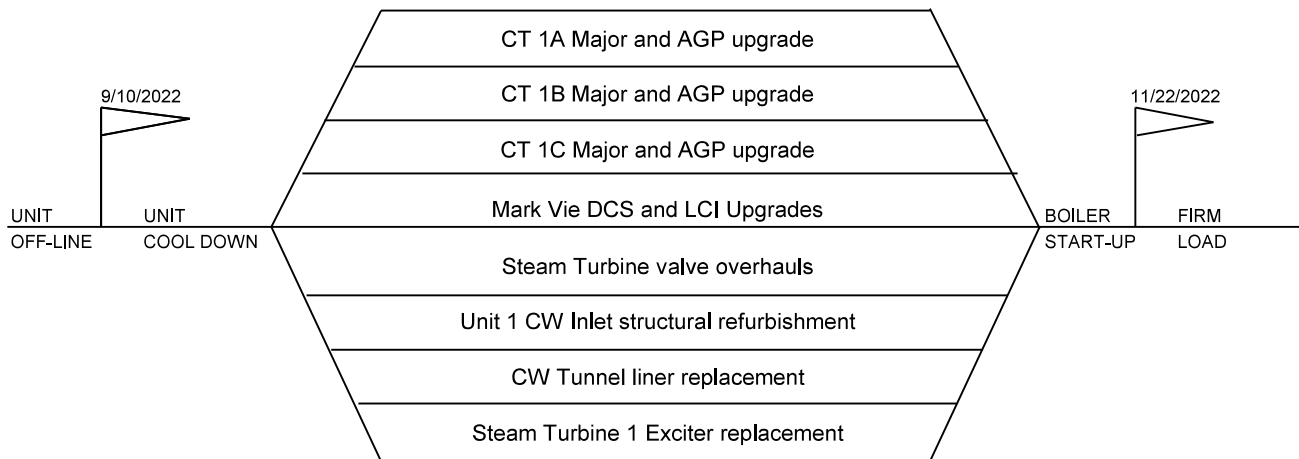
PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
BIG BEND 4	Apr 01 - Apr 14	Fuel System Clean
+	Oct 04 - Nov 02	High Energy Piping Hanger Installation
POLK 1	May 18 - May 24	Combined Cycle Planned Outage
POLK 2	Mar 03 - Mar 26	Combined Cycle Planned Outage
	Dec 13 - Dec 17	Combined Cycle Planned Outage
+	Sep 10 - Nov 22	CT 1A Major and AGP upgrade CT 1B Major and AGP upgrade CT 1C Major and AGP upgrade Mark Vie DCS and LCI Upgrades Steam Turbine valve overhauls Unit 1 CW Inlet structural refurbishment CW Tunnel liner replacement Steam Turbine 1 Exciter replacement
BAYSIDE 2	Nov 29 - Dec 12	Combined Cycle Planned Outage

+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2022 - DECEMBER 2022

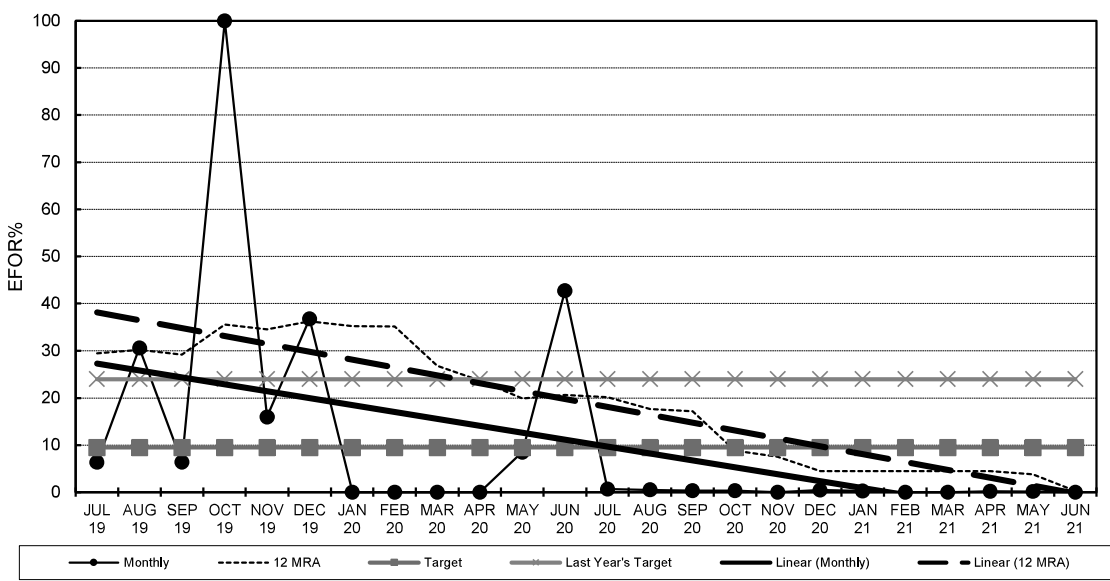


TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2022 - DECEMBER 2022

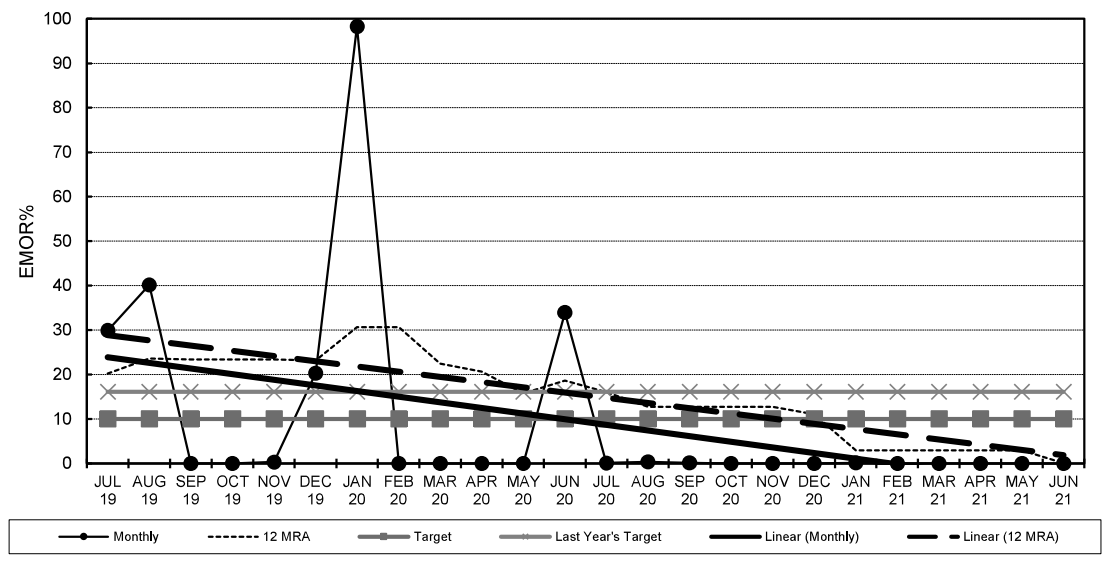


TAMPA ELECTRIC COMPANY
BAYSIDE 1
PLANNED OUTAGE 2022
PROJECTED CPM

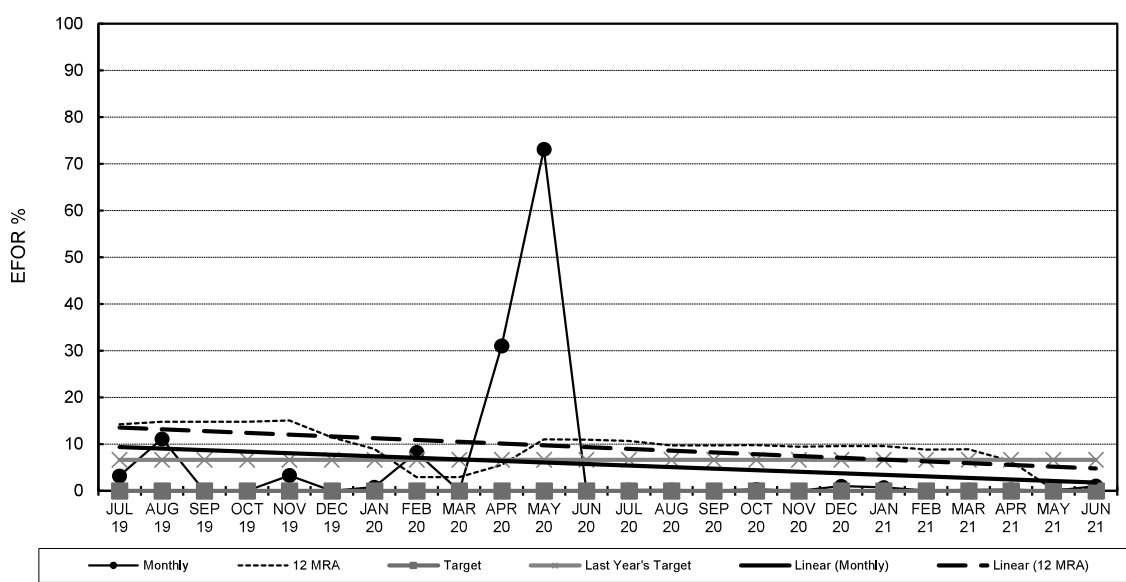
Big Bend Unit 4
EFOR



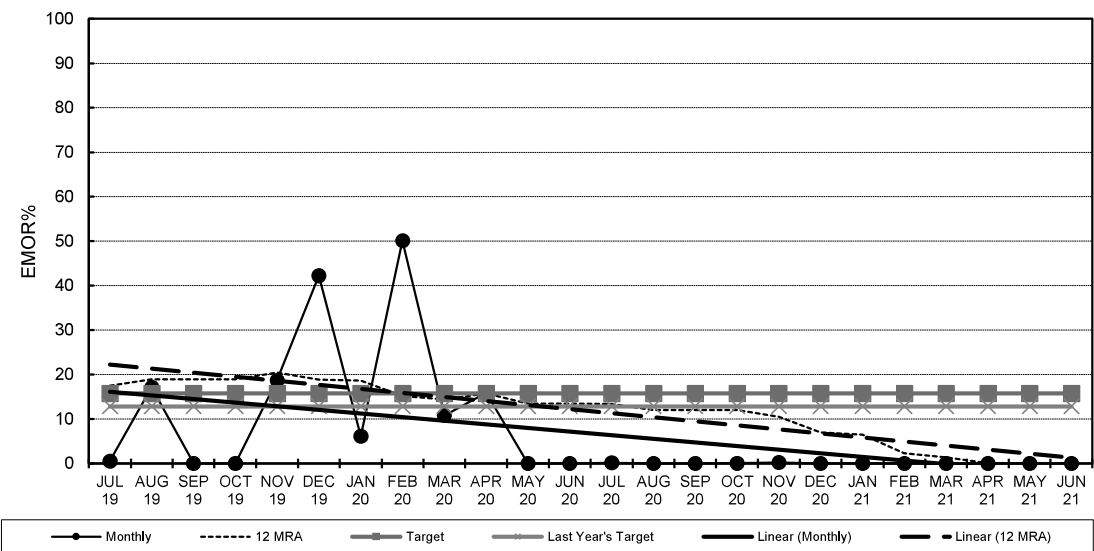
Big Bend Unit 4
EMOR



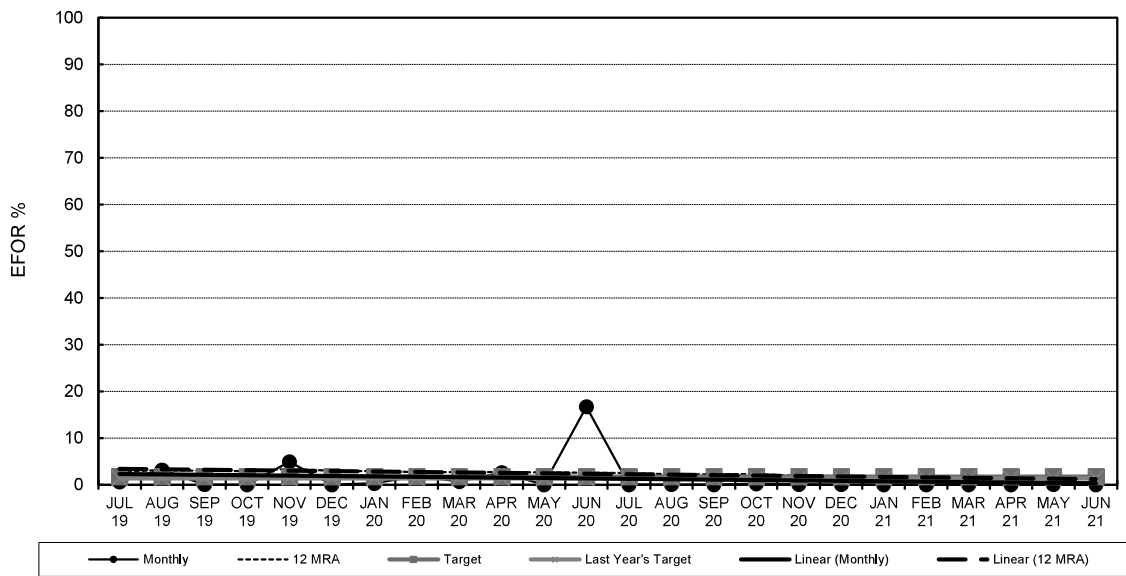
Polk Unit 1
EFOR



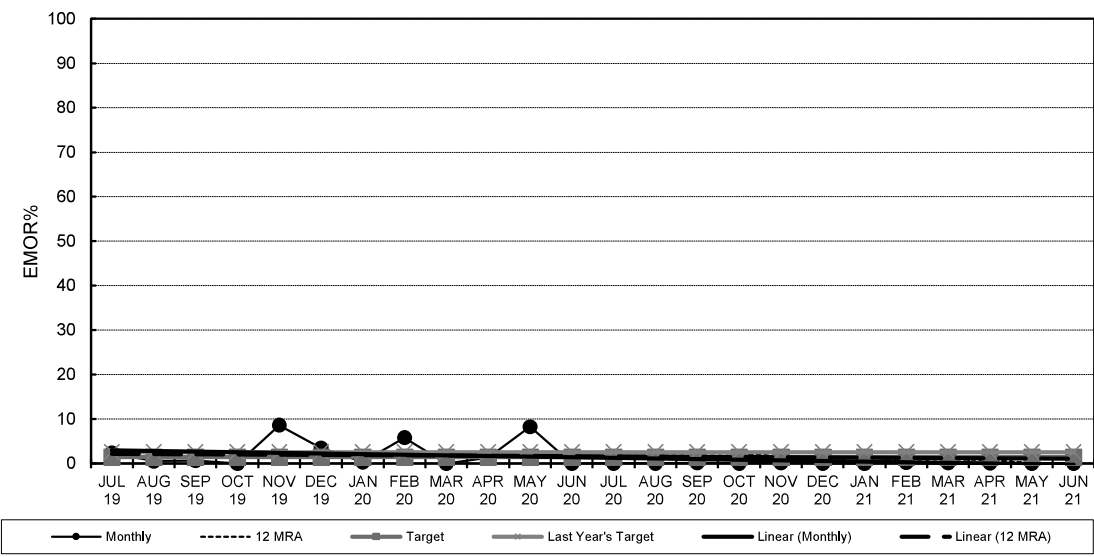
Polk Unit 1
EMOR



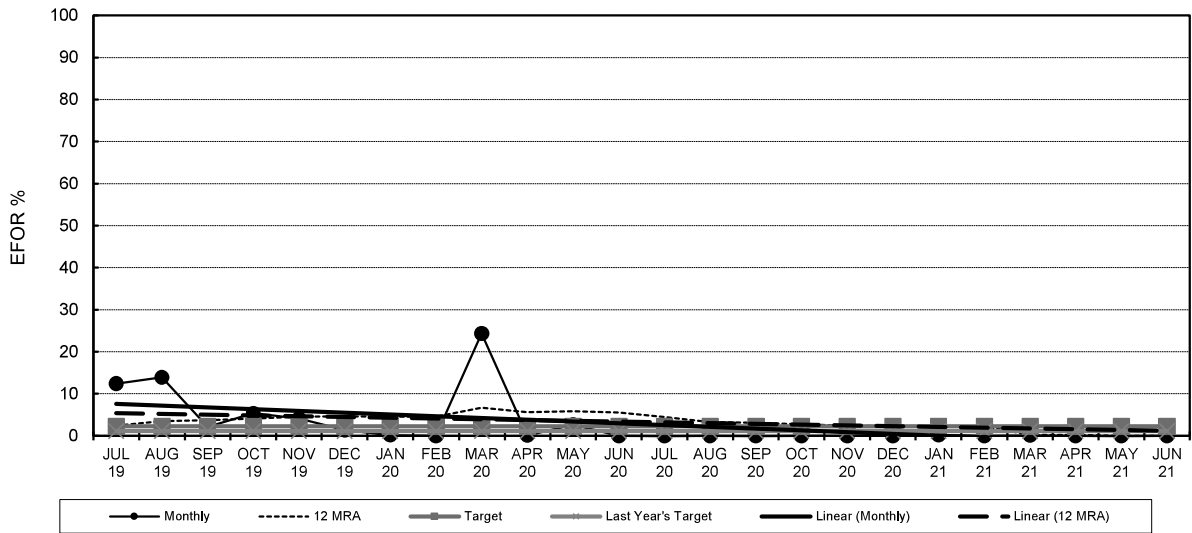
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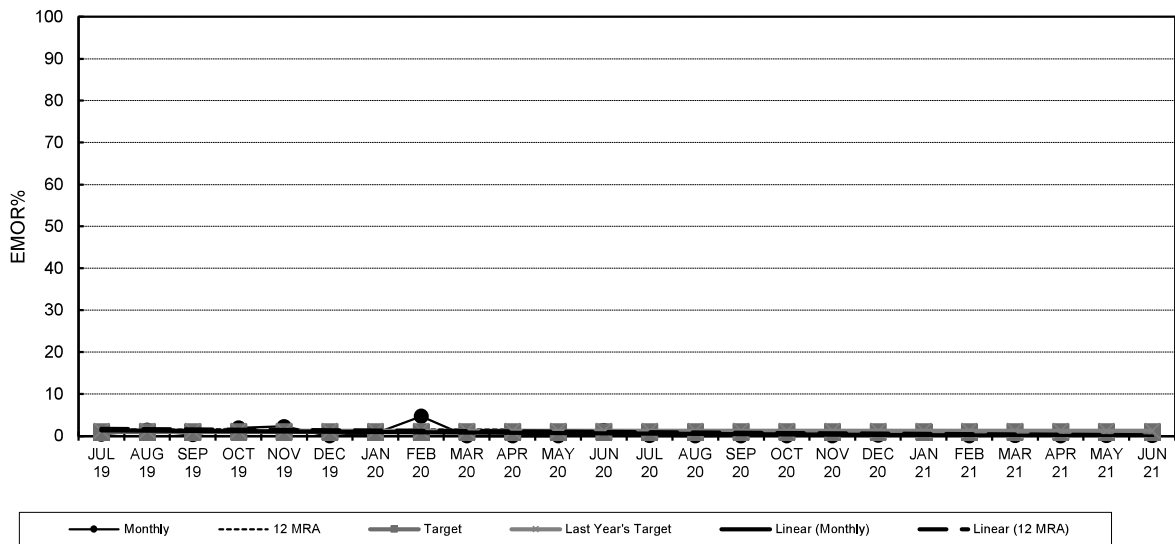
Polk Unit 2
EMOR



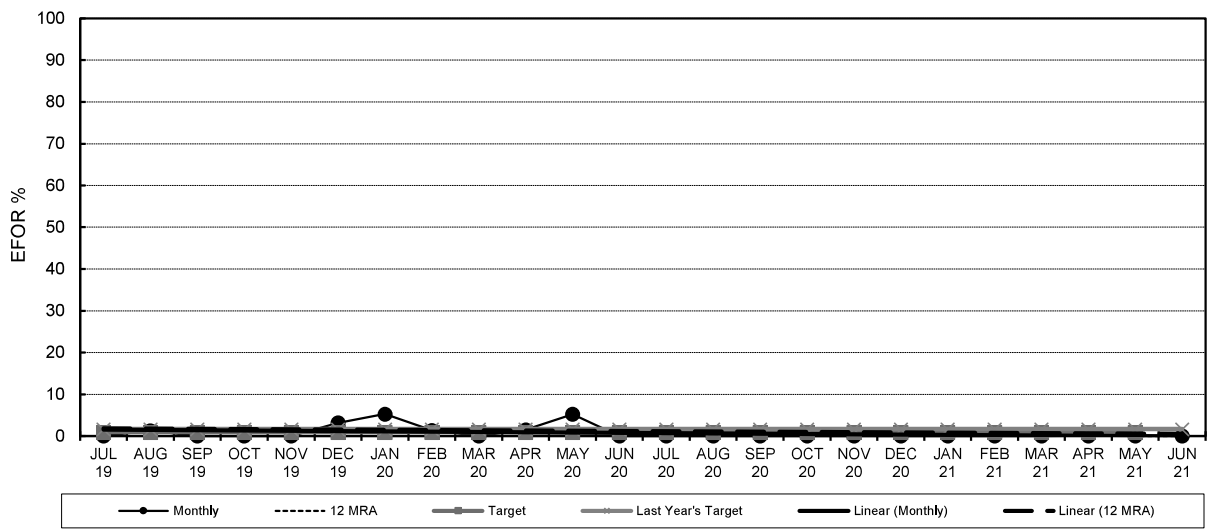
Bayside Unit 1
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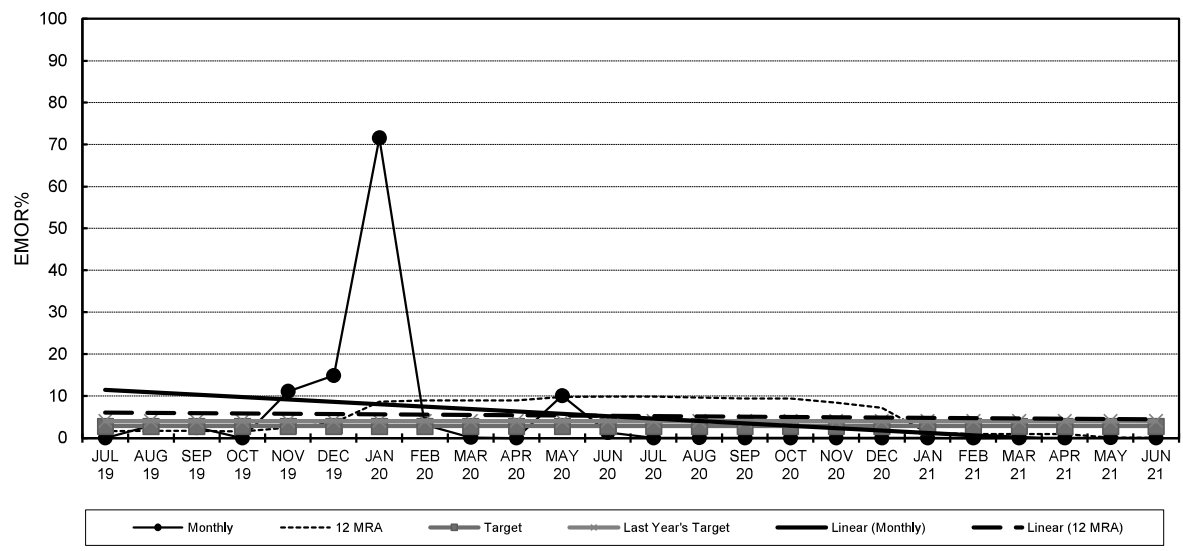
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EMOR



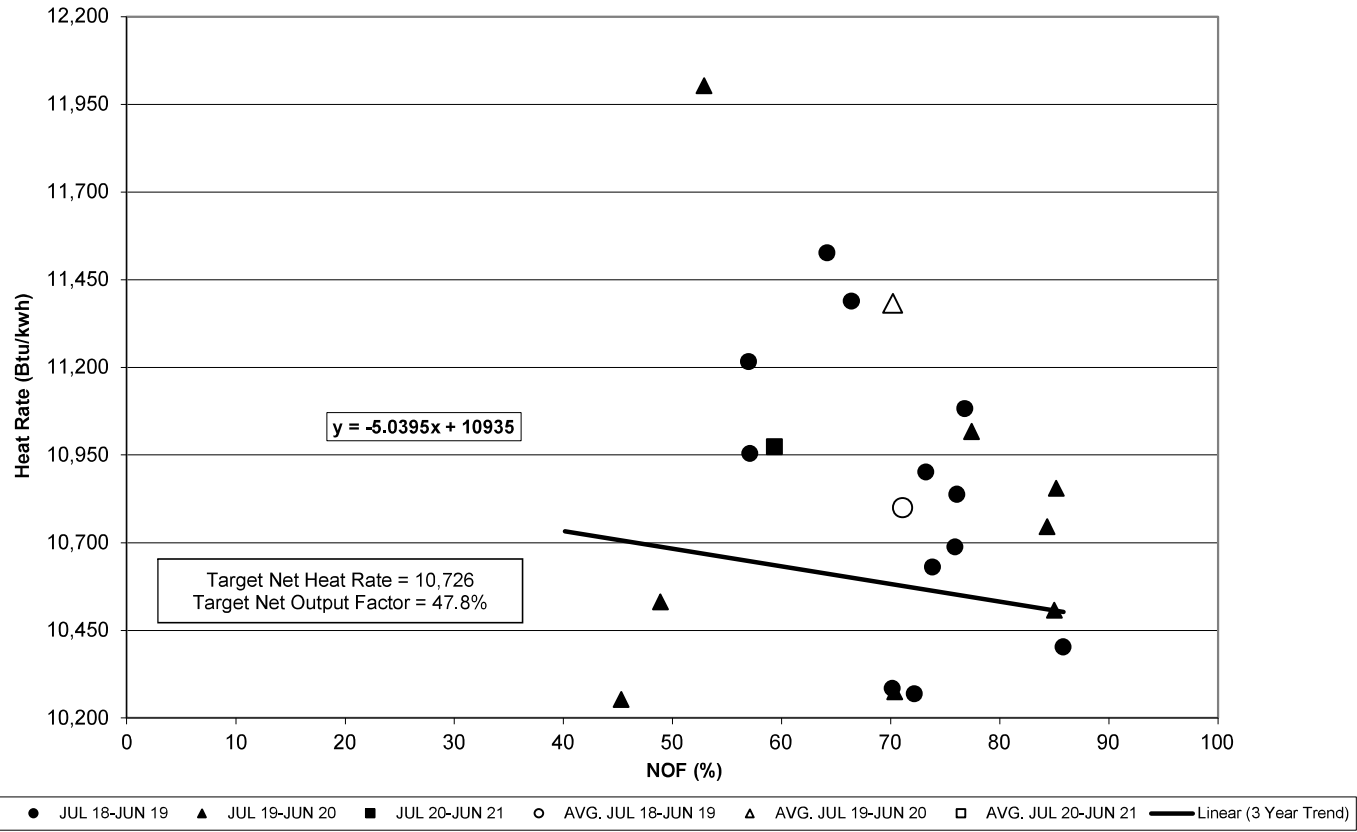
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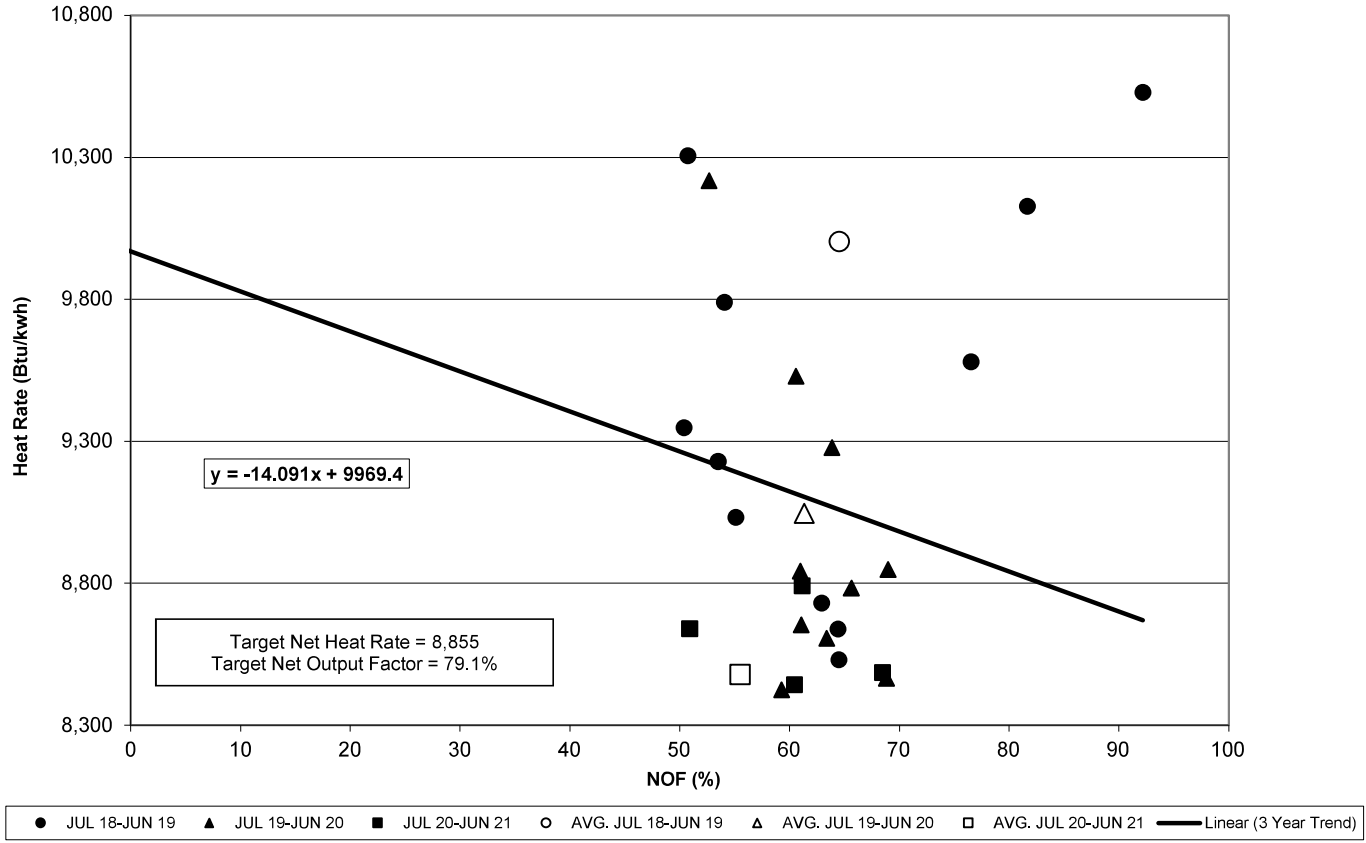
Bayside Unit 2
EMOR



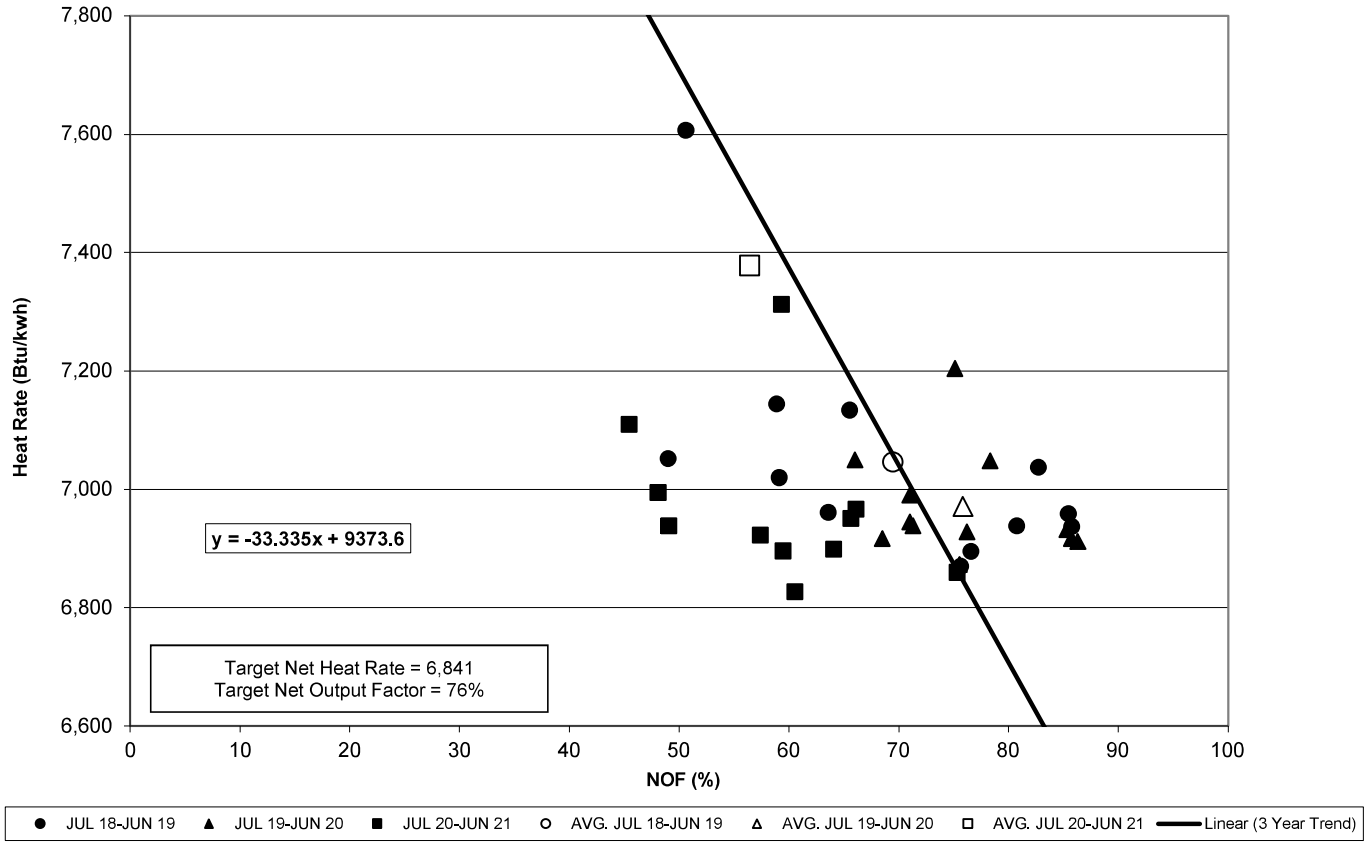
Tampa Electric Company Heat Rate vs Net Output Factor Big Bend Unit 4



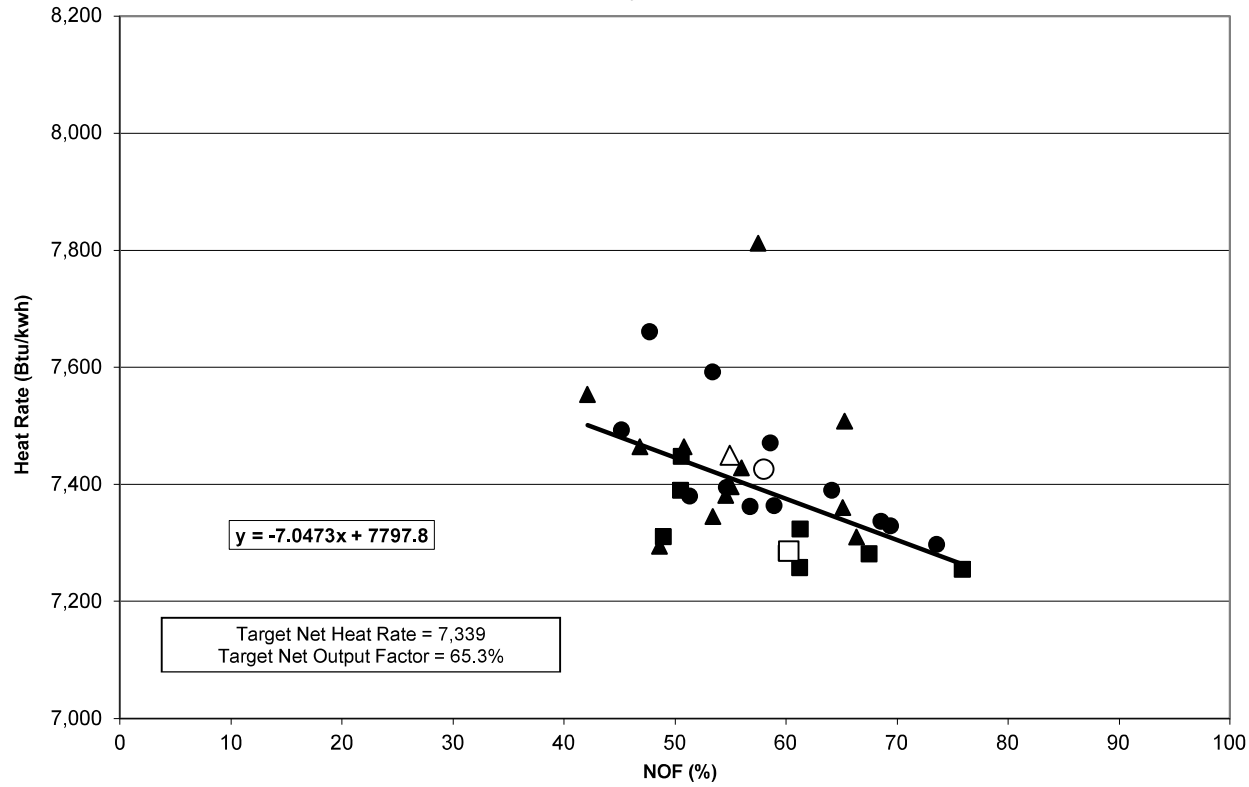
Tampa Electric Company Heat Rate vs Net Output Factor Polk Unit 1



Tampa Electric Company Heat Rate vs Net Output Factor Polk Unit 2



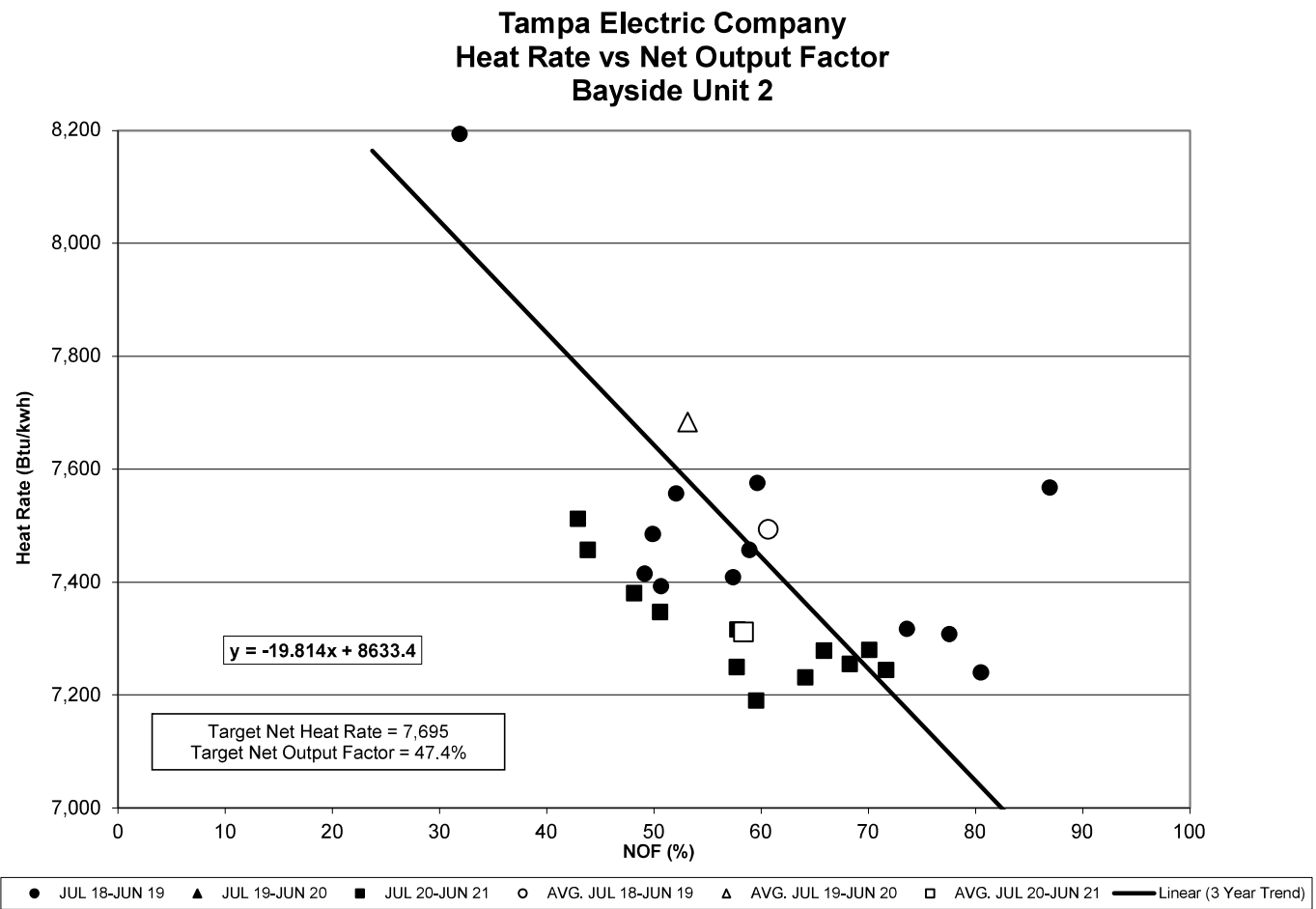
Tampa Electric Company Heat Rate vs Net Output Factor Bayside Unit 1



● JUL 18-JUN 19 ▲ JUL 19-JUN 20 ■ JUL 20-JUN 21 ○ AVG. JUL 18-JUN 19 △ AVG. JUL 19-JUN 20 □ AVG. JUL 20-JUN 21 — Linear (3 Year Trend)

ORIGINAL SHEET NO. 8,401,20E
PAGE 28 OF 32

EXHIBIT NO. _____ (PAB-2)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
DOCUMENT NO. 1
PAGE 28 OF 32



**TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2022 - DECEMBER 2022**

<u>PLANT / UNIT</u>	<u>ANNUAL GROSS MDC (MW)</u>	<u>ANNUAL NET NDC (MW)</u>
BIG BEND 4	458	425
POLK 1	225	217
POLK 2	1,130	1,107
BAYSIDE 1	740	731
BAYSIDE 2	979	968
GPIF TOTAL	<u>3,533</u>	<u>3,449</u>
SYSTEM TOTAL	5,153	5,025
% OF SYSTEM TOTAL	68.6%	68.6%

**TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2022 - DECEMBER 2022**

<u>PLANT / UNIT</u>	<u>ANNUAL GROSS MDC (MW)</u>	<u>ANNUAL NET NDC (MW)</u>
BAYSIDE 1	740	731
BAYSIDE 2	979	968
BAYSIDE 3	59	58
BAYSIDE 4	59	58
BAYSIDE 5	59	58
BAYSIDE 6	59	58
BAYSIDE TOTAL	<u>1,954</u>	<u>1,930</u>
BIG BEND 1	0	0
BIG BEND 2	363	343
BIG BEND 3	368	348
BIG BEND 4	458	425
BIG BEND CT4	59	58
BIG BEND TOTAL	<u>1,249</u>	<u>1,175</u>
POLK 1	225	217
POLK 2	1,130	1,107
POLK TOTAL	<u>1,355</u>	<u>1,324</u>
SOLAR	596	596
SOLAR TOTAL	<u>596</u>	<u>596</u>
SYSTEM TOTAL	<u><u>5,153</u></u>	<u><u>5,025</u></u>

**TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2022 - DECEMBER 2022**

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	6,959,410	37.07%	37.07%
BAYSIDE	2	3,498,360	18.64%	55.71%
BAYSIDE	1	3,127,400	16.66%	72.37%
SOLAR		1,544,800	8.23%	80.60%
BIG BEND	4	1,417,510	7.55%	88.15%
BIG BEND	1	756,930	4.03%	92.19%
POLK	1	501,150	2.67%	94.86%
BIG BEND	3	375,250	2.00%	96.85%
BIG BEND	5	256,820	1.37%	98.22%
BIG BEND	6	192,610	1.03%	99.25%
BAYSIDE	5	31,110	0.17%	99.41%
BAYSIDE	6	30,020	0.16%	99.57%
BAYSIDE	3	27,280	0.15%	99.72%
BIG BEND CT	4	26,660	0.14%	99.86%
BAYSIDE	4	25,860	0.14%	100.00%
BIG BEND	2	-	0.00%	100.00%

TOTAL GENERATION	18,771,170	100.00%
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GENERATION BY COAL UNITS: <u>1,417,510</u> MWH	GENERATION BY NATURAL GAS UNITS: <u>15,808,860</u> MWH
--	--

% GENERATION BY COAL UNITS <u>7.55%</u>	% GENERATION BY NATURAL GAS UNITS: <u>84.22%</u>
---	--

GENERATION BY SOLAR UNITS: <u>1,544,800</u> MWH	GENERATION BY GPIF UNITS: <u>15,503,830</u> MWH
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% GENERATION BY SOLAR UNIT <u>8.23%</u>	% GENERATION BY GPIF UNITS: <u>82.59%</u>
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EXHIBIT TO THE TESTIMONY

OF

PATRICK A. BOKAR

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS
JANUARY 2022 - DECEMBER 2022

**TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2022 - DECEMBER 2022**

Unit	Availability			Net Heat Rate
	EAF	POF	EUOF	
Big Bend 4¹	71.7	12.1	16.2	10,726
Polk 1²	87.7	1.9	10.3	8,855
Polk 2³	89.3	7.9	2.7	6,841
Bayside 1⁴	77.4	20.3	2.4	7,339
Bayside 2⁵	92.7	3.8	3.4	7,695

1 Original Sheet 8.401.20E, Page 12

2 Original Sheet 8.401.20E, Page 13

3 Original Sheet 8.401.20E, Page 14

4 Original Sheet 8.401.20E, Page 15

5 Original Sheet 8.401.20E, Page 16

**EXHIBIT TO THE TESTIMONY OF
JOHN C. HEISEY**

**OPTIMIZATION MECHANISM RESULTS
JANUARY 2020 – DECEMBER 2020**

**TAMPA ELECTRIC
OPTIMIZATION MECHANISM
Actual for the Period: January 2020 through December 2020**

TOTAL GAINS THRESHOLD SCHEDULE-Table 1							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Month	Wholesale Sales Total Gains (\$)	Wholesale Purchases Total Savings (\$)	Asset Optimization Gains (\$)	Total Monthly Gains (\$)	Threshold 1 Gains ≤ \$4.5 M (\$)	Threshold 2 \$4.5M < Gains ≤ \$8.0M (\$)	Threshold 3 Gains > \$8.0 M (\$)
				(2) + (3) + (4)			
January	1,078	4,043	(14,561)	(9,440)	(9,440)	-	-
February	10,468	9,476	20,789	40,733	40,733	-	-
March	100,898	46,812	47,847	195,557	195,557	-	-
April	-2,651	280,567	24,000	301,916	301,916	-	-
May	2,719	527,252	256,699	786,670	786,670	-	-
June	14,396	640,860	24,000	679,256	679,256	-	-
July	15,210	1,398,873	24,000	1,438,083	1,438,083	-	-
August	19,372	1,266,104	24,000	1,309,476	1,067,225	242,251	-
September	27,444	522,119	46,511	596,074	-	596,074	-
October	205,371	593,535	24,000	822,906	-	822,906	-
November	15,663	386,193	24,000	425,856	-	425,856	-
December	12,899	18,061	24,000	54,960	-	54,960	-
Total	422,867	5,693,895	525,285	6,642,047	4,500,000	2,142,047	-

TOTAL GAINS SHARING SCHEDULE-Table 2							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Month	Threshold 1 Gains ≤ \$4.5 M 100% Customer Benefit (\$)	Threshold 2 \$4.5M < Gains ≤ \$8.0M 40% Customer Benefit (\$)	Threshold 2 \$4.5M < Gains ≤ \$8.0M 60% TEC Benefit (\$)	Threshold 3 Gains > \$8.0 M 50% Customer Benefit (\$)	Threshold 3 Gains > \$8.0 M 50% TEC Benefit (\$)	Total Customer Benefits (\$)	Total TEC Benefits (\$)
January	(9,440)	-	-	-	-	(9,440)	-
February	40,733	-	-	-	-	40,733	-
March	195,557	-	-	-	-	195,557	-
April	301,916	-	-	-	-	301,916	-
May	786,670	-	-	-	-	786,670	-
June	679,256	-	-	-	-	679,256	-
July	1,438,083	-	-	-	-	1,438,083	-
August	1,067,225	96,900	145,351	-	-	1,164,125	145,351
September	-	238,430	357,644	-	-	238,430	357,644
October	-	329,162	493,744	-	-	329,162	493,744
November	-	170,342	255,514	-	-	170,342	255,514
December	-	21,984	32,976	-	-	21,984	32,976
Total	4,500,000	856,819	1,285,228	-	-	5,356,819	1,285,228

TAMPA ELECTRIC
WHOLESALE POWER DETAIL
Actual for the Period: January 2020 through December 2020

Wholesale Sales-Table 3

(1)	(2)	(3)	(4)	(5)
	Wholesale Sales	Wholesale Gross Gains	Third Party Transmission Costs	Total Net Wholesale Sales Gains
Month	(MWh)	(\$)	(\$)	(\$)
				(3) + (4)
January	150	1,956	(878)	1,078
February	900	13,013	(2,545)	10,468
March	9,946	148,895	(47,997)	100,898
April	1,425	3,887	(6,538)	-2,651
May	225	4,124	(1,405)	2,719
June	1,254	21,883	(7,487)	14,396
July	1,835	26,299	(11,089)	15,210
August	2,424	33,061	(13,689)	19,372
September	2,405	42,197	(14,753)	27,444
October	15,214	335,664	(130,293)	205,371
November	1,125	19,940	(4,277)	15,663
December	1,240	29,229	(16,330)	12,899
Total	38,143	680,148	(257,281)	422,867

Wholesale Purchases-Table 4

(1)	(2)	(3)	(4)	(5)
	Wholesale Purchases	Wholesale Savings	Capacity Purchases	Total Net Wholesale Purchase Gains
Month	(MWh)	(\$)	(\$)	(\$)
				(3) + (4)
January	2,715	4,043	-	4,043
February	2,675	9,476	-	9,476
March	2,350	46,812	-	46,812
April	80,260	280,567	-	280,567
May	156,387	527,252	-	527,252
June	295,805	640,860	-	640,860
July	305,357	1,398,873	-	1,398,873
August	296,177	1,266,104	-	1,266,104
September	281,385	522,119	-	522,119
October	215,900	593,535	-	593,535
November	147,600	386,193	-	386,193
December	24,755	18,061	-	18,061
Total	1,811,366	5,693,895	-	5,693,895

TAMPA ELECTRIC
ASSET OPTIMIZATION DETAIL-Table 5
Actual for the Period: January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)
Month	Natural Gas Storage Optimization (\$)	Natural Gas AMA Gains (\$)	Resale of Solid Fuel (\$)	Total Asset Optimization Gains (\$)
January				(14,561)
February				20,789
March				47,847
April				24,000
May				256,699
June				24,000
July				24,000
August				24,000
September				46,511
October				24,000
November				24,000
December				24,000
Total	-	305,425	219,860	525,285

TAMPA ELECTRIC COMPANY FUEL PROCUREMENT AND WHOLESALE POWER PURCHASES RISK MANAGEMENT PLAN 2022

Introduction

Tampa Electric serves its retail customers' electricity needs through a portfolio of generation and wholesale purchases. Tampa Electric's generation fuel mix is primarily a blend of natural gas, solar and coal. The company's risk management activities focus on maintaining supplies of fuel to ensure reliable service. Pursuant to Order No. PSC-2017-0451-AS-EU, the company does not currently maintain nor execute any financial hedges to mitigate natural gas price volatility.

I. Qualitative and Quantitative Risk Management Objectives

A. Qualitative objectives

Tampa Electric's goals in managing risks associated with fuel or power purchases are focused on minimizing supply risk to ensure reliability of electric service to its customers at a reasonable price. To the extent price risk can be reduced without compromising supply reliability or imposing unnecessary costs on customers, Tampa Electric is committed to executing strategies to accomplish its risk management goals.

B. Quantitative objectives

Tampa Electric's quantitative objective is to prudently manage its fuel and wholesale energy procurement activities to minimize the variance from projected expenditures while taking advantage of cost-saving opportunities that do not result in increased supply risk. Tampa Electric has established a portfolio of fuel and purchased power products with creditworthy counterparties for known volumes and prices.

II. Oversight & Reporting of Fuel Procurement Activities

The company provides fuel and wholesale energy procurement activities with independent and unavoidable oversight.

- A.** The TECO Energy Board of Directors established an Energy Risk Management Policy ("Risk Policy"). This policy governs all energy commodities transacting activities at each of TECO Energy's operating units. The scope of this policy includes:

- Roles and responsibilities of various persons and functions with respect to risk management
 - Authorized transacting activity
 - Risk limits
 - Valuation and data management
 - Credit risk management
 - Reporting
 - Compliance and enforcement
- B.** The Risk Policy established the Risk Advisory Committee (“RAC”). The responsibilities of the RAC include the following activities:
- Reviewing the Risk Management Policy periodically and recommending changes and enhancements for approval by the Board of Directors (“Board”).
 - Reviewing corporate risk limits for recommendation to the Board.
 - Establishing the quantitative limits for operating companies within Board approved corporate risk limits. The RAC may, at its discretion, delegate approval of sub-limits to operating company management.
 - Approving parameters for counterparty credit limits and the allocation of limits among the operating companies.
 - Establishing guidelines for risk management and measurement.
 - Overseeing and reviewing the risk management process and infrastructure.
 - Reviewing and approving transacting strategies proposed by the operating companies.
 - Understanding and approving methodologies used for valuation and risk measurement.
 - Reviewing and approving corporate and operating company risk limits.
 - Establishing credit underwriting standards, and monitoring credit risk-taking activities and related exposures.
 - Reviewing risk reports, including portfolio risk summaries and profitability and performance summaries.
 - Enacting, maintaining, and enforcing limit violation and trader misconduct policies.
 - Taking appropriate courses of action when the risk position of a transacting group has exceeded or is approaching the established limits.
 - Reviewing and approving new risk management products.
 - Presenting periodic reports to the Board or its committees.
- C.** TECO Energy established a corporate risk management function (“middle office”), which is overseen by the Senior Director, Enterprise Risk Management.
- D.** Tampa Electric established additional oversight or control mechanisms to ensure compliance with policies and procedures. The following practices

provide checks and balances on fuel and purchased power procurement activities.

- Fuel and wholesale energy procurement activities are conducted in accordance with company guidelines, including review by Fuels and Executive management.
- All agreements are formalized in a written contract that is reviewed by legal counsel and commercial sponsors.
- The contracts are reviewed by the Senior Director, Enterprise Risk Management of TECO Energy's Energy Risk Management Department for potential credit risks and incorporation of appropriate credit protection.
- The company maintains approval authority restrictions based on term and value of the transaction.
- Payments of invoices under each contract are settled and approved by an independent department.
- Each transaction is eligible for review by outside, internal and regulatory auditors, and audits are performed regularly.
- Information systems provide transaction authority control, credit monitoring, and, if applicable, mark-to-market and value-at-risk analysis and other key controls.

E. In accordance with the Risk Policy, Tampa Electric established commodity specific transaction limits for commodity transactions.

- The RAC reviews and approves commodity transaction limits on an individual basis.
- The limits include commodity, physical or financial, tenor (time limit), and dollar amount.
- If applicable, only a few individuals are authorized to execute financial hedging transactions.

F. Although the company does not currently engage in financial hedging, Tampa Electric's Fuels Department has applicable policies and procedures. The key elements of its policies and procedures are:

- Financial hedging of fuel commodities is for mitigation of risk to fuel price uncertainty and volatility.
- Hedging will be conducted in a manner consistent with the Risk Management Plan approved by the RAC.
- Execution of hedges under the Risk Management Plan will be consistent with approved transaction limits for authorized transactors.
- Duties will be separated to assure sufficient control over hedging transactions.
- Hedging activity will be monitored regularly and reported at least once a month to ensure consistency with the Risk Management Plan.

G. Reports are generated that summarize the fuel procurement activities of the company. These include monthly financial reports produced by Regulatory

Accounting, FERC Electric Quarterly Reports, FERC Form 1, FERC Form 580, FERC Form 923, FERC Form 552, FPSC Form 423, FPSC A-Schedules and E-Schedules. In addition, position and, if applicable, mark-to-market reports are produced and reviewed by the Senior Director, Enterprise Risk Management. The appropriate entries and related disclosures are made in the company's books and records as required by accounting standards.

III. Risk Assessment

In its Risk Policy, TECO Energy has identified the following types of risks for its commodity portfolio.

A. Market Risk

Market risk is the potential change in value of a commodity contract caused by adverse changes in market factors (price and volatility). The following are types of market risk.

1. **Price Risk:** Price risk refers to the uncertainty associated with changes in the price of an underlying asset. For instance, if a company has a short position in the market (e.g., needs to meet load requirements by purchasing electricity or natural gas), it will be susceptible to price increases. Conversely, if a company is in a long position (e.g., excess generation or natural gas supply), it is exposed to decreases in market prices. Currently, Tampa Electric manages its price risk using physical hedges.

In 2022, Tampa Electric is subject to limited price risk related to variation in coal prices. That price risk is mitigated in part because the company has already contracted for much of its expected coal needs at known prices. Expected market conditions do not currently require further price risk mitigation, for the reasons described in Section IV of this plan.

Tampa Electric evaluated its exposure to changes in the price for natural gas during 2022 based on the forward price forecasts from various consultants and agencies including the Energy Information Administration ("EIA") and S&P Scenario Planning Service and the company's expected usage under both low and high price natural gas cases. Natural gas expenditures decrease in the low case by an estimated \$22.0 million, and total fuel and purchased power costs decrease by \$22.5 million due to lower prices. In the high case, natural gas expenditures increase by an estimated \$35.2 million, and the total fuel and purchased power costs increase by \$ 36.4 million.

Tampa Electric requires small quantities of fuel oil and maintains a contract that eliminates its supply risk. Due to the small quantities of fuel oil needed for generation, the cost impact caused by price risk is minimal and is therefore not quantified.

2. **Time Spread Risk:** This is the risk that the relationship between two points (*i.e.*, one month versus six months) on the forward curve changes. Because the shape of the fuel or electricity forward curve changes to reflect the market's expectations of spot and future fuel or electricity prices, the relationship between any two points on the curve is not always constant. Because of the nature of its business Tampa Electric has little reason or opportunity to offset energy commodity requirements in one month with resources delivered in another month. Therefore, time spread risk is not a significant issue for Tampa Electric.
3. **Liquidity Risk:** Liquidity risk is associated with the lack of marketability of a commodity. It includes the risk of an adverse cost or return variation stemming from the lack of marketability of a financial instrument. Liquidity risk may arise because a given position is very large relative to typical trading volumes of like commodity and contract tenor, or because market conditions are unsettled. Liquidity risk is usually reflected in a wide bid-ask spread and large price movements in response to any attempt to buy or sell. A firm facing the need to quickly unwind a portfolio of illiquid instruments may find it necessary to sell at prices far below fair value. Tampa Electric is not exposed to liquidity risk for natural gas financial instruments since the company does not use financial hedges. Tampa Electric does have some liquidity risk for wholesale power transactions since the Florida market has a limited number of participants.
4. **Basis Risk:** Basis risk is the risk exposure due to a difference in commodity value between different delivery points. Electricity markets are regional. Prices can be different at different locations because of differences in both supply costs and the cost of transmission between the two locations. These price differences are dynamic, primarily due to changes in transmission availability between the two locations. Power basis risk is not a significant issue for the company as most of our purchased power is sourced from the Florida market. Due to the low consumption of coal, Tampa Electric's negligible use of oil, and the sourcing of natural gas supply with index contract pricing at or close to the Henry Hub, gas basis risk is not a significant issue for the company.

Fundamentally, market risk is created by the existence of "open" positions. An open position is the difference between an existing requirement and the ability to meet that requirement with existing

resources.

B. Volume Risk

Volume risk is the potential adverse economic impact of unanticipated changes in supply or demand. Tampa Electric faces supply risk, because there is uncertainty associated with the availability of generating units or fuel availability for those units. If a generating unit fails, Tampa Electric must replace the power with another unit's generation or with purchased power at market prices. If fuel supply is curtailed, Tampa Electric utilizes contracted natural gas storage capacity and/or backup fuel to mitigate fuel supply risk. Tampa Electric also faces demand risk since there is uncertainty associated with customer demand, and thus uncertainty in the determination of the fuel or energy purchase volumes necessary to supply such demand. Tampa Electric's volume risk for fuel and purchased power in 2022 will be managed operationally and through contract terms enforcement, including appropriate legal remedies, should a party default.

C. Credit Risk

Credit risk is the risk of financial loss due to a counterparty's failure to fulfill the terms of a contract on a timely basis. It includes both settlement risk associated with payment for fuel or energy received, as well as the potential risk that the counterparty defaults on an obligation to provide or receive fuel or energy. Credit risk depends on the probability of counterparty default, the concentration of credit exposure with a small number of counterparties, the total amount of exposure, and the volatility of markets. Tampa Electric's current credit risk will vary based on the number of its trading counterparties. Tampa Electric's existing credit risk is minimal since it uses a wide variety of counterparties and has systems and processes in place to monitor and control credit risk.

D. Administrative Risk

Administrative risk is risk of loss associated with deficiencies in a company's internal control structure and management reporting due to human error, fraud, or a system's inability to adequately capture, store and report transactions. The company has consistently maintained appropriate administrative controls for entering and administration of commodity transactions.

IV. Risk Management Strategy and Current Hedging Activity

Tampa Electric's risk management strategy is designed to limit exposure to different types of risk that are applicable to the company's operation.

A. Market Risk

Tampa Electric's potential market risk is the result of open positions in four commodities:

- Natural Gas
- Coal
- Fuel Oil
- Purchased Power

System energy requirements during 2022 are projected to be served in the proportions shown in the following table.

Commodity	Percent of System Energy
Natural Gas	82
Solar	10
Coal	7
Purchased Power	1

Based on Tampa Electric's assessment of market risk factors, the company has implemented the market risk management strategies described below.

1. **Coal:** Tampa Electric has contracted for much of its expected coal needs for 2022 through bilateral agreements with coal producers. The company will provide the projected amounts in both tons and dollars in its 2022 projection filing to be submitted September 3, 2021. Coal prices are expected to remain low in the near term as generation shifts toward renewables and domestic demand for coal continues to decline. Tampa Electric has secured a majority of its coal needs for 2022, reducing exposure to price volatility and mitigating coal volume risk. Tampa Electric's contracts with suppliers also incorporate legal remedies in the event of default, which address volume risk.
2. **Fuel Oil:** In 2022, Tampa Electric will continue to purchase its fuel oil needs at indexed market prices. Oil represents less than one percent of the company's needs on a GWH basis, and therefore, associated cost impacts from price risk are minimal. Tampa Electric maintains a contract with a local supplier to deliver all of its needs, which mitigates supply risk.
3. **Natural Gas:** Tampa Electric will prepare its annual natural gas supply Request for Proposal ("RFP") in Quarter 3, 2021 to procure 70 to 90 percent of its gas requirements for 2022. The company procures the balance of its requirements monthly or daily as

requirements become more certain. All products procured in the annual RFP are at indexed market prices.

Natural gas prices are subject to short term volatility. The drop in natural gas prices during the pandemic, price swings during extreme events like Winter Storm Uri in February 2021, and current price increases associated with the increased demand from the economic rebound outpacing the slow production recovery illustrate the significant and frequent types of events that drive natural gas price volatility. However, long term gas prices are expected to remain relatively low as production growth from shale gas and associated gas from shale oil production is expected to continue.

Pursuant to Order No. PSC-2017-0451-AS-EU, Tampa Electric has discontinued its financial hedging program for natural gas and is not able to resume hedging until the expiration of its moratorium, on December 31, 2022.

4. **Purchased Power:** Total forecasted purchased power for 2022 is 422 GWH. The 2022 forecasted wholesale energy purchases will be purchased from as-available cogenerators or on the short-term, non-firm market for economy purposes.

The company's purchased power contracts include a fuel component; therefore, Tampa Electric has exposure to fuel price risk for its wholesale energy purchases, particularly for purchased power supplied from natural gas-fired generation. Tampa Electric has never hedged wholesale energy transactions with financial instruments due to the lack of a liquid, published wholesale energy market and appropriate available instruments.

In summary, Tampa Electric's planned operations in 2022 result in nominal market risk associated with coal and fuel oil. Non-price risks associated with natural gas and purchased power are also minimal.

5. **Volume Risk:** Hedging of volumetric risk is problematic due to a limited number of viable financial hedging instruments. Tampa Electric has identified the following physical hedges.
 - Maintaining appropriate inventory stockpiles provides a physical hedge against volume risk.
 - "Swing" contracts enable the buyer to take variable volumes up to a predefined limit.
 - Full requirement contracts enable the buyer to take any volume up to total usage.

Tampa Electric uses inventory swing contracts and full requirements contracts where needed commodity volumes are small and in situations where commodity volumes are unpredictable in volume and/or timing. Other alternatives will continue to be identified, assessed, and implemented as necessary.

6. **Credit Risk:** TECO Energy's credit risk management process is composed of the following primary steps.
 - Gather counterparty information for initial evaluation.
 - Assess counterparty creditworthiness and assign credit limit.
 - Determine credit collateral requirements, as needed.
 - Request, review and monitor contractual requirements, legal covenants, collateral documents and credit provisions.
 - Quantify counterparty exposure and measure against approved limits.
 - Monitor counterparty and credit support provider qualities.
 - Prepare credit exposure reports on a daily basis that are reviewed prior to entering into transactions.
7. **Administrative Risk:** Tampa Electric maintains energy trading risk management systems and processes to efficiently track, monitor and evaluate contracts and trading activities. Tampa Electric's administrative processes and system controls have passed repeated internal and external (Sarbanes-Oxley) audits.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET: 20210001-EI EXHIBIT: 49

PARTY: Staff Exhibit 49

DESCRIPTION: FPUC's Responses to Staff's First Set of Interrogatories, Nos. 1-3. (Bates No. 00001-00018)

49

FPUC's Responses to Staff's First Set of Interrogatories, Nos. 1-3.

Interrogatory No. 1

INTERROGATORIES

Please refer to the Direct Testimony of Mr. Curtis Young, filed with Florida Public Utilities Company's (FPUC or Company) *Petition for Approval of Final True-Up Amount for 2020* for the following questions.¹

1. Please refer to page 4, lines 1-5. With respect to customer refunds relating to the Tax Cuts and Jobs Act, please provide a citation to a Company filing/schedule that supports the statement: “. . . \$27,870 of which was attributed to 2019.”

Company Response:

By Order No. PSC-2020-0083-PAA-EI, issued in Docket No. 20200033-EI on March 20, 2020, the Commission approved Amendment No. 1 to the Stipulation and Settlement originally entered into between the Company and the Office of Public Counsel in 2017. (See attached file Order Approving Amendment No. 1 to 2017 Stipulation and Settlement-01530-2020). Amendment No. 1 to the Stipulation and Settlement specifically addressed the treatment of changes in the State Corporate Income Tax rates. Within Amendment No. 1, the Company estimated that “For calendar year 2019, the NOI annual tax savings impact of \$35,825 will be applied to the Company’s existing fuel and purchased power cost recovery balance. . . .”² The Company has included in the attached Exhibit A its calculations of the estimated \$35,825, as well as the actual \$27,870 tax savings attributed to 2019. It should be noted that, as reflected in Article II of Amendment No. 1, the amounts reflected in the Amendment No. 1 were understood to be estimates.

Respondent: Curtis D. Young

¹Document No. 03196-2021, filed April 2, 2021.

² See Order No. PSC-2020-0083-PAA-EI, at page 7 (Attachment A), Article III.

Interrogatory No. 2

2. Please refer to page 4, lines 5-9. With respect to the Hurricane Michael interim rate refund, is the final refund/accounting entry related to the interim rates, or are there any additional or forthcoming true ups to be performed? If so, please discuss.

Company Response:

Yes, the final refund/accounting entry is related to the interim rates. There are no additional or forthcoming true-ups to be performed with respect to the Hurricane Michael interim rate refund.

Respondent: Curtis D. Young

Interrogatory No. 3

3. Please show in detail the derivation of the “over-collected base revenues – Hurricane Michael Settlement” amount appearing on (CDY-1), page 1 of 3 (i.e., \$975,259).

Company Response:

See attached Exhibit B.

Respondent: Curtis D. Young

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DOCKET NO. 20210001-EI

DATED: May 11, 2021

DECLARATION

I hereby certify and affirm that I sponsored the Company's responses to COMMISSION STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY, Nos. 1 - 3 in Docket No. 20210001-EI. The responses are true and correct to the best of my knowledge.

Under penalty of perjury, I declare that I have read the foregoing declaration and the interrogatory responses identified above, and that the facts stated therein are true.

s/Curtis D. Young

(name), Declarant

Dated: May 11, 2021

FLORIDA PUBLIC UTILITIES COMPANY
Computation of Electric Tax Savings
Projected 2019 Test Year

Response/Staff Interrogatory 1 **Exhibit A.****Page 1 of 2****With ARAM changes****ANNUAL TAX SAVINGS FROM RATE CHANGE:**

NOI BEFORE TAX CHANGE (INCLUDES LIMITED PROCEEDING)	\$ 3,261,790
NOI AFTER TAX CHANGE (INCLUDES LIMITED PROCEEDING)	\$ 3,279,529
NET INCOME EFFECT OF TAX CHANGE	\$ 17,739
GROSS UP	\$ 6,022
PRETAX - GROSSED UP SAVINGS (EXPENSE)	\$ 23,761

ESTIMATED REGULATORY TAX LIABILITY:

Estimated Protected Grossed Up Reg Tax Liability	\$ 34,384
Estimated Unprotected Grossed Up Reg Tax Liability	
Total Regulatory Tax Liability	\$ 34,384

Per ARAM 2018 Schedule

Amortization 2018 Per ARAM Schedules (by Year)

	<u>2019</u>	<u>2020</u>	<u>2021</u>
\$	12,064	\$ 11,388	\$ 10,932
Total refund estimated	\$ 35,825	\$ 35,149	\$ 34,693

FLORIDA PUBLIC UTILITIES COMPANY
Computation of Electric Tax Savings
Actual Annual 2019 Test Year

Response/Staff Interrogatory 1 **Exhibit A.**

Page 2 of 2

With ARAM changes

ANNUAL TAX SAVINGS FROM RATE CHANGE:

Income Tax Expense Before Tax Change	\$ 254,677
Income Tax Expense After Tax Change	<u>\$ 246,407</u>
NET INCOME EFFECT OF TAX CHANGE	\$ 8,270
GROSS UP	<u>\$ 2,687</u>
PRETAX - GROSSED UP SAVINGS (EXPENSE)	<u><u>\$ 10,957</u></u>

ESTIMATED REGULATORY TAX LIABILITY:

Protected Grossed Up Reg Tax Liability	\$ 16,913
Unprotected Grossed Up Reg Tax Liability	<u> </u>
Total Regulatory Tax Liability	<u><u>\$ 16,913</u></u>

Per ARAM 2018 Schedule

2019

Amortization 2018 Per ARAM Schedules \$ 16,913

Total actual refund

\$ 27,870

20210001.EI Staff Hearing Exhibits 00008

Revenue Details per Hurricane Michael Settlement

Response/Staff Interrogatory 3 Exhibit B.

Approved Revenue Per Settlement Agreement DOCKET No. 20190156-EI, ORDER No. PSC-2020-0347-AS-EI

Base Rate Increase: see <i>Attachment A, Page 9, Paragraph 10</i>	3,355,080
Storm Surcharge: see <i>Attachment A, Page 9, Paragraph 10</i>	7,658,985
Total Revenue Requirement	<u>11,014,065</u>

Monthly Amount	917,838.75
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Reserve Balance by Month

	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Total
Reserved Interim Revenue	844,839.33	882,197.60	1,097,719.88	881,140.17	892,278.84	1,015,618.19	1,204,863.54	1,220,334.44	1,112,522.99	1,002,132.42	10,153,647.40
Approved Revenue	917,838.75	917,838.75	917,838.75	917,838.75	917,838.75	917,838.75	917,838.75	917,838.75	917,838.75	917,838.75	9,178,387.50
Overcollection	(72,999.42)	(35,641.15)	179,881.13	(36,698.58)	(25,559.91)	97,779.44	287,024.79	302,495.69	194,684.24	84,293.67	975,259.90

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Joint motion for approval of Amendment
No. 1 to stipulation and settlement, by Florida
Public Utilities Company and Office of Public
Counsel.

DOCKET NO. 20200033-EI
ORDER NO. PSC-2020-0083-PAA-EI
ISSUED: March 20, 2020

The following Commissioners participated in the disposition of this matter:

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

NOTICE OF PROPOSED AGENCY ACTION
ORDER APPROVING AMENDMENT NO. 1 TO
2017 STIPULATION AND SETTLEMENT

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code (F.A.C.).

CASE BACKGROUND

On July 3, 2017, Florida Public Utilities Company (FPUC or Company) petitioned the Commission to include \$15,241,515 in capital projects in its rate base and increase its rates and charges by the amount necessary to recover the revenue requirement of \$1,823,869 on those projects. These projects fell into three categories: (1) grid modernization and safety; (2) storm hardening; and (3) an interconnection with Florida Power & Light Company (FPL). The Office of Public Counsel (OPC) intervened on September 21, 2017, and the parties entered into a Stipulation and Settlement (2017 Settlement) resolving all issues which was approved by Order No. PSC-2017-0488-PAA-EI.¹

Article VII of the 2017 Settlement addresses changes in the federal or state corporate income tax rates and requires that federal or state corporate tax savings be addressed through a base rate reduction within 120 days of the effective date of such change.

On September 12, 2019, the Florida Department of Revenue issued a Tax Information Publication (TIP) announcing that the Florida corporate income tax rate was reduced from 5.500

¹Order No. PSC-2017-0488-PAA-EI, issued December 26, 2017, in Docket No. 20170150-EI, *In re: Petition for limited proceeding to include reliability and modernization projects in rate base, by Florida Public Utilities Company*.

percent to 4.458 percent effective retroactively to January 1, 2019, and continuing through December 31, 2021. The TIP indicates that the Florida corporate income tax rate will return to 5.50 percent effective January 1, 2022.

On January 22, 2020, to address this Florida tax change, FPUC and OPC filed a Joint Motion for Approval of Amendment No. 1 to Stipulation and [2017] Settlement (Joint Motion). Amendment No. 1 is Attachment A to this order. Both OPC and FPUC agree that the impact of the State Tax Rate change on FPUC's NOI associated with base rates is approximately \$35,000 annually for years 2019 through 2021. Acknowledging the tax savings amounts are based upon FPUC's best estimates, FPUC calculated the actual amount of the tax benefit to be flowed-through to customers. For calendar year 2019, the NOI annual tax savings impact of \$35,825 will be applied to the Company's existing fuel and purchased power cost recovery balance with interest, which will serve to reduce FPUC's Fuel Cost Recovery factors for 2021. The savings for calendar years 2020 and 2021 will be trued-up to actual and applied to the Company's existing fuel and purchased power cost recovery balances in 2020 and 2021 with interest, thereby reducing FPUC's Fuel Cost Recovery factors for 2022 and 2023. If approved by this Commission, this State Tax Amendment will take effect upon our approval and expire on December 31, 2023, unless otherwise modified by our order.

We have jurisdiction over this request under Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

DECISION

The standard for approval of a settlement agreement is whether it is in the public interest.² A determination of public interest requires a case-specific analysis based on consideration of the proposed settlement taken as a whole.³

It is significant that OPC, the statutory representative for all Florida ratepayers, negotiated and is a signatory to Amendment No. 1. The intent of the 2017 Settlement was to timely pass on any reductions in state or federal corporate taxes to the ratepayers via a reduction in base rates. This state corporate tax reduction, unlike the 2017 federal corporate tax reduction,

² Order No. PSC-2017-0488-PAA-EI, issued on December 26, 2017, in Docket No. 20170150-EI, *In re: Petition for limited proceeding to include reliability and modernization projects in rate base, by Florida Public Utilities Company*; Order No. PSC-13-0023-S-EI, issued on January 14, 2013, in Docket No. 120015-EI, *In re: Petition for increase in rates by Florida Power & Light Company*; Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket Nos. 080677 and 090130, *In re: Petition for increase in rates by Florida Power & Light Company and In re: 2009 depreciation and dismantlement study by Florida Power & Light Company*; Order No. PSC-13-0023-S-EIPSC-10-0398-S-EI, issued June 18, 2010, in Docket Nos. 090079-EI, 090144-EI, 090145-EI, 100136-EI, *In re: Petition for increase in rates by Progress Energy Florida, Inc., In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc., In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc., and In re: Petition for approval of an accounting order to record a depreciation expense credit, by Progress Energy Florida, Inc.*; Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, *In re: Petition for rate increase by Progress Energy Florida, Inc.*

³ Order No. PSC-13-0023-S-EI, at p. 7.

is not permanent but will only be in effect from January 1, 2019 until December 31, 2021. Under these circumstances, both OPC and FPUC have concluded that crediting FPUC's fuel and purchased power cost recovery balance with the annual tax savings generated by the decrease in state corporate income tax plus interest for the years 2020 and 2021 is the most efficient method to give ratepayers the benefit of the tax decrease. Further, this method stabilizes base rates for the immediate future. Based on these factors, we find that taken as a whole Amendment No. 1 to the 2017 Settlement is a reasonable treatment of the tax savings associated with the temporary reduction in state corporate income taxes and we hereby approve it.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Joint Motion for Approval of Amendment No. 1 to Stipulation and Settlement is hereby granted and Amendment No. 1, as stated on Attachment A, is hereby approved. It is further

ORDERED that Amendment No. 1 will take effect on March 3, 2020, and will expire on December 31, 2023, unless otherwise modified by this Commission. It is further

ORDERED that the provisions of this order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, F.A.C., is received by the Office of the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that, if a protest is filed within 21 days of the issuance of this order, Amendment No. 1 shall remain in effect, subject to true-up, pending resolution of the protest. If no timely protest is filed, this docket shall be closed upon the issuance of a Consummating Order.

By ORDER of the Florida Public Service Commission this 20th day of March, 2020.



ADAM J. TEITZMAN

Commission Clerk

Florida Public Service Commission

2540 Shumard Oak Boulevard

Tallahassee, Florida 32399

(850) 413-6770

www.floridapsc.com

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

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on April 10, 2020.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Joint Motion for Approval of Amendment) Docket No.
to Stipulation and Settlement to Address State)
Income Tax Flow Through.)
_____) January 21, 2020

AMENDMENT NO. 1 TO STIPULATION AND SETTLEMENT

WHEREAS, on July 3, 2017, Florida Public Utilities Company ("FPUC" or "Company") petitioned the Florida Public Service Commission ("the Commission") for a limited proceeding to include \$15,241,515 in capital projects in rate base and increase its rates and charges by the amount necessary to recover the revenue requirement of \$1,823,869 on those projects with the effective day of such rate increase to be January 1, 2018 ("Limited Proceeding"); and

WHEREAS, on September 21, 2017, the Office of Public Counsel ("OPC") intervened in that proceeding on behalf of the Citizens of Florida; and

WHEREAS, the Parties entered into a Stipulation and Settlement to resolve the Limited Proceeding ("Limited Proceeding Settlement"), which was filed November 28, 2017, and approved by Commission Order No. PSC-2017-0488-PAA-EI, issued December 26, 2017; and

WHEREAS, the Limited Proceeding Settlement provided for an increase to FPUC's base rates sufficient to generate an additional \$1,558,050 of annual revenues to be implemented January 1, 2018, for purposes of recovering the revenue requirement on certain specified projects;

WHEREAS, Article VII of the Limited Proceeding Settlement recognized that federal or state Tax Reform could impact the effective tax rate recognized by the Company in FPSC-adjusted reported net operating income and the measurement of existing and prospective deferred federal income tax assets and liabilities reflected in the FPSC adjusted capital structure; and

WHEREAS, on September 12, 2019, the Florida Department of Revenue issued a Tax Information Publication ("TIP") announcing that the Florida corporate income tax rate was

reduced from 5.5 percent to 4.458 percent effective retroactive to January 1, 2019 and continuing in effect through December 31, 2021 ("State Tax Rate Change"); and

WHEREAS, the TIP indicates that the Florida corporate income tax rate will return to 5.5 percent effective January 1, 2022; and

WHEREAS, the Parties agree that the state corporate income tax rate reduction became effective before the Limited Proceeding Settlement expired; and

WHEREAS, Section VII of the Limited Proceeding Settlement required that federal or state corporate tax savings be addressed through a base rate reduction within 120 days of the effective date of such change; and

WHEREAS, FPUC and OPC have signed this Amendment No. 1 ("State Tax Amendment") to the Limited Proceeding Settlement addressing an alternative mechanism by which the tax savings associated with the temporary state corporate income tax rate reduction will be passed on to FPUC's customers that is more efficient and equally beneficial; and

WHEREAS, unless the context clearly intends otherwise, the term "Party" or "Parties" shall mean a signatory or signatories to this State Tax Amendment; and

WHEREAS, the legal system, as well as the Commission, favors settlement of disputes for a variety of reasons, including that they are in the public interest; and

WHEREAS, the Parties to this State Tax Amendment, individually and collectively, agree that this State Tax Amendment, taken as a whole, is in the public interest; and

WHEREAS, the Parties have entered into this State Tax Amendment in compromise of positions taken in accord with their rights and interests under Chapters 350, 366 and 120, Florida Statutes, as applicable, and as part of a negotiated exchange of consideration among the Parties, each Party has agreed to concessions to the others with the expectation, intent, and understanding such that all provisions of this State Tax Amendment, upon approval by the Commission, will be enforced by the Commission as to all matters addressed herein with respect to both Parties; and

WHEREAS, the Parties agree that this State Tax Amendment is consistent with the underlying intent of the Limited Proceeding Settlement approved in Docket No. 20170150-EI; and

NOW, THEREFORE, in consideration of the foregoing and the mutual covenants set forth herein, which the Parties agree constitute good and valuable consideration, the Parties hereby stipulate and agree as follows:

I. This State Tax Amendment will take effect upon Commission approval ("Effective Date") and expire December 31, 2023, unless otherwise modified by Commission order.

II. The Parties agree that the impact of the State Tax Rate change on FPUC's Net Operating Income ("NOI") associated with base rates is a savings of approximately \$35,000 annually for years 2019 through 2021.

III. The Parties agree that the tax savings identified herein are based upon FPUC's best estimates at the time of the filing of this State Tax Amendment. FPUC shall calculate the actual amount of the tax benefit to be flowed-through to customers.

III. For calendar year 2019, the NOI annual tax savings impact of \$35,825 will be applied to the Company's existing fuel and purchased power cost recovery balance with interest, which will serve to reduce FPUC's Fuel Cost Recovery factors for 2021. The savings for calendar years 2020 and 2021 will be trued-up to actual and applied to the Company's existing fuel and purchased power cost recovery balances in 2020 and 2021 with interest, thereby reducing FPUC's Fuel Cost Recovery factors for 2022 and 2023.

VI. The Parties reserve all rights, unless such rights are expressly waived or released, under the terms of this State Tax Amendment.

VII. The Parties hereto agree that this State Tax Amendment is in the public interest. As such, the Parties agree that this State Tax Amendment should be approved. The Parties likewise agree and acknowledge that the Commission's approval of this State Tax Amendment promotes planning and regulatory certainty for both FPUC and its customers.

VIII. The Parties agree that they will support this State Tax Amendment and will not request or support any order, relief, outcome, or result in conflict with the terms of this State Tax Amendment in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this State Tax Amendment or the subject matter hereof.

IX. No Party will assert in any proceeding before the Commission that this State Tax Amendment or any of the terms herein shall have any precedential value. The Parties' agreement to the terms in this State Tax Amendment shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving this State Tax Amendment.

X. The provisions of this State Tax Amendment modify the provisions of Section VII the Limited Proceeding Settlement and survive the expiration of the Limited Proceeding Settlement only to the extent expressly set forth herein.

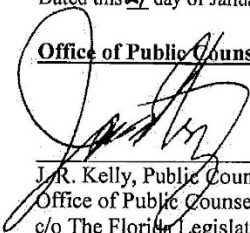
VIII. This State Tax Amendment is dated as of January 21, 2020. It may be executed in one (1) or more counterparts, all of which will be considered one and the same State Tax Amendment and each of which will be deemed an original.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this State Tax Amendment by their signature(s).

Dated this 21 day of January 2020.

Office of Public Counsel



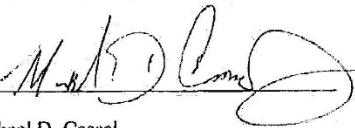
J.R. Kelly, Public Counsel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, Florida 32399-1400

Docket No. 20190156-EI

IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this State Tax Amendment by their signature(s).

Dated this 21 day of January 2020.

Florida Public Utilities Company

By: 

Michael D. Cassel
Assistant Vice President, Florida Public Utilities Company

50

DEF's Response to Staff's Third Set of
Interrogatories, Nos. 3-4.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 20210001-EI

Dated: August 30, 2021

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFF'S THIRD SET OF INTERROGATORIES (NOS. 3-4)**

Duke Energy Florida, LLC ("DEF") responds to the Staff of the Florida Public Service Commission ("Staff") Third Set of Interrogatories (Nos. 3-4) as follows:

INTERROGATORIES

3. Please refer to the Direct Testimony of Duke Energy Florida (DEF or Company) witness Gary P. Dean, filed with *DEF's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up for the Period of January 2021 through December 2021*, Exhibit GPD-2, Part 1, Schedule E1-B, pages 1-2, line 5 for the following request.¹ Please detail what specific costs/items are included in the category "[a]djustments to [f]uel [c]ost" appearing on this Schedule.

Response:

The total \$15.30 million on Exhibit GPD-2, Part 1, Schedule E1-B, page 2 of 2, line 5 consists of various adjustments to 2021 actual/estimated fuel costs including:

- \$13.20 million amortization of the Florida Power Development (FPD), LCC qualifying facility regulatory asset per Order No. PSC-2018-0240-PAA-EQ.
- \$1.94 million adjustment 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.
- \$0.16 million in annual net metering settlement costs to participating customers.
- \$1,220 allocation of University of Florida steam revenues.

¹Document No. 08364-2021, filed July 27, 2021.

Hedging

4. What is/are the specific type(s) of hedging transactions contemplated to be employed by the Company for the purposes of hedging its future natural gas purchases?

Response:

DEF will utilize a phased hedging program where financial hedge transactions are executed over time. DEF will use two types of financial transactions to hedge which are swaps and costless collars. The volumes hedged represent a portion of DEF's forecasted natural gas burns with higher hedging target ranges in the near term and lower hedging target ranges in the outer period.

AFFIDAVIT

STATE OF FLORIDA

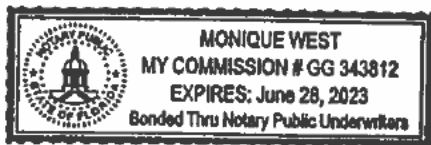
COUNTY OF PINELLAS

I hereby certify that on this 24th day of August, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GARY P. DEAN, who is personally known to me, and has acknowledged before me that he provided the answer to interrogatory number 3, of STAFF'S THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 3-4) in Docket No. 20210001-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24th day of August, 2021.



Gary P. Dean





Notary Public
State of Florida, at Large

My Commission Expires: 6/28/2023

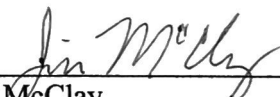
AFFIDAVIT

STATE OF NORTH CAROLINA

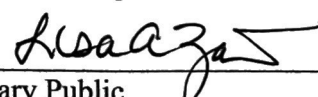
COUNTY OF ~~MECKLENBURG~~ Lincoln

I hereby certify that on this 25 day of Aug, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JIM MC CLAY, who is personally known to me, and has acknowledged before me that he provided the answer to interrogatory number 4, of STAFF'S THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 3-4) in Docket No. 20210001-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 25 day of August, 2021.


Jim McClay




Notary Public
State of North Carolina, at Large

My Commission Expires: 3-19-23

51

FPL's Response to Staff's Third Set of
Interrogatories, No. 7

(7-Supplemental)
(Including attachment)

**Florida Power & Light Company
Docket No. 20210001-EI
Staff's 3rd Set of Interrogatories
Interrogatory No. 7
Page 1 of 1**

QUESTION:

Please refer to the Direct Testimony of Florida Power & Light (FPL or Company) witness Renae B. Deaton, filed with the Company's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up for the period January 2021 through December 2021, for the following questions.

Please refer to Exhibit RBD-3, page 1 of 57, Schedule E1-B, line 32 for the following question. Please explain how both the actual and projected SolarTogether credit amounts were/are formulated. Please show all calculations.

RESPONSE:

The actual SolarTogether credits for January 2021-June 2021 shown on line 32 of Schedule E1-B, represent the actual subscription credits that appeared on participant bills during that time period. The subscription credit amount is calculated on each participant's subscription level in kilowatts, the actual SolarTogether generation produced, and number of years the customer has participated in the program:

$$\begin{array}{lcl} \text{Monthly} & & \text{Actual SolarTogether Generation (kWh) x SolarTogether tariff credit} \\ \text{Subscription} & = & (\$/\text{kWh}) \text{ rate for year of participation x participant subscription (kW) /} \\ \text{Credit} & & \text{SolarTogether nameplate capacity (kW)} \end{array}$$

FPL is updating the actual/estimated 2021 fuel true-ups in conjunction with the 2022 projection filings on September 3, 2021 and will provide updated actual/estimates for the SolarTogether credits at that time. FPL will also supplement this response at that time.

**Florida Power & Light Company
Docket No. 20210001-EI
Staff's 3rd Set of Interrogatories
Interrogatory No. 7 (Supplemental)
Page 1 of 1**

QUESTION:

Please refer to the Direct Testimony of Florida Power & Light (FPL or Company) witness Renae B. Deaton, filed with the Company's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up for the period January 2021 through December 2021, for the following questions.

Please refer to Exhibit RBD-3, page 1 of 57, Schedule E1-B, line 32 for the following question. Please explain how both the actual and projected SolarTogether credit amounts were/are formulated. Please show all calculations.

RESPONSE:

The actual SolarTogether credits for January 2021-July 2021 shown on line 32 of Schedule E1-B, represent the actual subscription credits that appeared on participant bills during that time period. The subscription credit amount is calculated on each participant's subscription level in kilowatts, the actual SolarTogether generation produced, and number of years the customer has participated in the program:

$$\begin{array}{lcl} \text{Monthly} & & \text{Actual SolarTogether Generation (kWh) x SolarTogether tariff credit} \\ \text{Subscription} & = & (\$/\text{kWh}) \text{ rate for year of participation x participant subscription (kW) /} \\ \text{Credit} & & \text{SolarTogether nameplate capacity (kW)} \end{array}$$

The 2021 forecasted SolarTogether subscription credits for August-December billings are calculated based on the forecasted generation estimates for the SolarTogether sites and assumes the program is fully subscribed at the time each facility achieved commercial operations. The detailed calculations are provided as Attachment 1 of this supplemental response.

DECLARATION

I sponsored the answer to Interrogatory No. 7 Supplemental from **STAFF'S THIRD SET OF INTERROGATORIES (NOS. 6-10)** to Florida Power & Light Company in Docket No. 20210001-EI. The responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and the interrogatory answers identified above, and that the facts stated therein are true.



Matthew Valle

Date: September 2nd, 2021

52

FPUC's Responses to Staff's Second Set of Interrogatories, Nos. 4-5.

INTERROGATORIES

Please refer to the Direct Testimony of Mr. Curtis Young, filed with Florida Public Utilities Company's (FPUC or Company) *Petition for Approval of Actual/Estimated True-Up Amount* for the following questions.¹

4. Please refer to page 4, lines 4-11. Does FPUC have specific authorization for fuel clause recovery of consulting fees paid to Pierpont and McLelland? If so, please identify. If not, please further explain the proposal for including such costs as recoverable fuel-related expenses.

FPUC RESPONSE:

The Company believes these costs are recoverable because:

- They are directly related to purchase power and have not been recovered through base rates;
- The Company currently does not have the resources or expertise to identify and pursue projects as well as negotiate contract terms that will produce cost savings which will ultimately be passed through to the customers; and
- The Commission has determined that these types of costs are appropriate for recovery by FPUC through the fuel and purchased power clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Additionally, costs associated with these particular consultants have been allowed for recovery in more recent Docket Nos. 20170001-EI, 20180001-EI, 20190001-EI, 20200001-EI and 20210001-EI.

Respondent: Curtis D. Young

¹Document No. 08344-2021, filed July 27, 2021.

Interrogatory No. 5

5. Referring to Schedule E1-B, under the header “Net Purchased Power Costs,” what activities/costs constitute “special costs” as labeled on this Schedule in the amount of \$185,717?

FPUC RESPONSE:

The “special costs” consist of consulting fees, legal fees and to a lesser degree, taxes on company use as indicated at the bottom left side corner of Schedule E1-B. These costs are particularly related to the purchase power agreement review and analysis. As the Commission has recognized time and again in previous dockets within this clause, the Company simply does not have the internal resources to pursue projects and initiatives designed to produce purchased power savings without engaging outside assistance for project analytics and due diligence, as well as negotiation and contract development expertise.

Respondent: Curtis D. Young

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

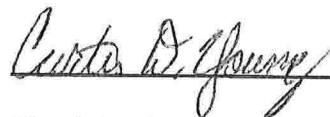
DOCKET NO. 20210001-EI

DATED: August 26, 2021

DECLARATION

I hereby certify and affirm that I sponsored the Company's responses to COMMISSION STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY, Nos. 4 - 5 in Docket No. 20210001-EI. The responses are true and correct to the Best of my knowledge.

Under penalty of perjury, I declare that I have read the foregoing declaration and the interrogatory responses identified above, and that the facts stated therein are true.



(Curtis D. Young), Declarant

Dated: August 26, 2021

53

DEF's Response to Staff's First Request to Produce Documents, No. 1.

(Including attachment)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost
Recovery Clause with Generating
Performance Incentive Factor

Docket No. 20210001-EI

Filed: October 1, 2021

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S
FIRST REQUEST TO PRODUCE DOCUMENTS (NO. 1)**

Duke Energy Florida, LLC ("DEF"), responds to the Staff of the Florida Service Public Commission's ("Staff"), First Request to Produce Documents (No. 1), as follows:

DOCUMENTS REQUESTED

1. Please submit alternative testimony and schedules that hypothetically assumes the Florida Public Service Commission denies Duke Energy Florida's Rate Mitigation Proposal as it relates to both fuel and capacity cost recovery.

Response:

Attached to this response are alternative schedules that hypothetically assume the Florida Public Service Commission denies Duke Energy Florida's Rate Mitigation Proposal as it relates to both fuel and capacity cost recovery.

DEF is including the following schedules that changed in response to this POD bearing bates numbers 20210001-DEF-000066 through 20210001-DEF-000073:

- Alternative Schedule E1
- Alternative Schedule E1-A
- Alternative Schedule E1-C
- Alternative Schedule E1-D
- Alternative Schedule E1-E
- Alternative Schedule E2
- Alternative Schedule E10
- Alternative Inverted Fuel Rate

There were no changes to any of the other schedules filed with the 2022 Projection filing on September 3, 2021.

Please note the following assumptions as it relates to this response and the rates identified in "STAFF 1st POD – Q1 Alternative Schedule E10".

- Base Rate – No change.

- Fuel Cost Recovery – DEF assumes that the Staff is asking DEF to re-calculate its 2022 fuel rates under the typical procedure that would include recovering the entire 2021 True-Up balance in 2022.
- Capacity Cost Recovery – No change. DEF would still propose to recover the CCR rates as filed in its 2022 Projection filing.
- ECCR – No change.
- ECRC – No change.
- SPPCRC – DEF will implement its SPPCRC as approved in Order No. PSC-2021-0324-FOF-EI.
- Interim Storm Charge (Eta & Isaias and Elsa) – DEF will continue with the Interim Storm Charge approved for Eta and Isaias in Order No. PSC-2021-0271-PCO-EI. DEF estimates an approximate \$18 million in storm restoration costs for Elsa that would be recovered from customers in 2022 (January – December).
- Asset Securitization Charge – No change.

Duke Energy Florida, LLC
 Fuel and Purchased Power Cost Recovery Clause
 Estimated for the Period of : January 2022 through December 2022

		<u>DOLLARS</u>	<u>mWh</u>	<u>CENTS/KWH</u>
1.	Fuel Cost of System Net Generation (E3)	1,342,122,966	40,554,861	3.3094
2.	Coal Car Investment	0	0	0.0000
3.	Adjustment to Fuel Cost	12,294,429	0	0.0000
4.	TOTAL COST OF GENERATED POWER	1,354,417,395	40,554,861	3.3397
5.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)	11,259,068	166,907	6.7457
6.	Energy Cost of Economy Purchases (E9)	2,973,141	66,432	4.4755
7.	Payments to Qualifying Facilities (E8)	114,130,163	2,664,397	4.2835
8.	TOTAL COST OF PURCHASED POWER	128,362,372	2,897,737	4.4297
9.	TOTAL AVAILABLE mWh		43,452,598	
10.	Fuel Cost of Economy Sales (E6)	(9,080,256)	(251,831)	3.6057
10a.	Gain on Economy Sales (E6)	(2,460,928)	(251,831) *	0.9772
10b.	Gain on Total Power Sales - 20% (E6)	172,656		
11.	Fuel Cost of Stratified Sales (E6)	(39,687,742)	(1,411,321)	2.8121
12.	TOTAL FUEL COST AND GAINS ON POWER SALES	(51,056,270)	(1,663,152)	3.0699
13.	Net Inadvertent Interchange			
14.	TOTAL FUEL AND NET POWER TRANSACTIONS	1,431,723,498	41,789,446	3.4260
15.	Net Unbilled	652,674 *	(46,267)	0.0017
16.	Company Use	5,706,535 *	(164,698)	0.0145
17.	T & D Losses	75,588,626 *	(2,206,272)	0.1920
18.	Adjusted System Sales	1,431,723,498	39,372,209	3.6342
19.	Wholesale Sales (Excluding Supplemental Sales)	(597,064)	(17,150)	3.4814
20.	Jurisdictional Sales	1,431,126,434	39,355,059	3.6364
21.	Jurisdictional Sales Adjusted for Line Losses x 1.00028	1,431,527,149	39,355,059	3.6375
22.	Prior Period True-Up (Sch E1-A)	246,837,576	39,355,059	0.6272
23.	Total Jurisdictional Fuel Cost	1,678,364,725	39,355,059	4.2647
24.	GPIF **	2,657,279	39,355,059	0.0068
25.	CEC Bill Credit	11,109,749	39,355,059	0.0282
26.	Fuel Factor Adjusted including GPIF & CEC Bill Credit	1,692,131,754	39,355,059	4.2997
27.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)			4.3000

* For Informational Purposes Only

** Based on Jurisdictional Sales

Duke Energy Florida, LLC
Calculation of Total True-Up
(Projected Period)

Estimated for the Period of : January 2022 through December 2022

1. Estimated Over/(Under) Recovery January - December 2021 (Schedule E1-B, Page 2 of 2, Section C, Lines 8 and 12 - Dec 21)	\$	(246,837,576)
2. Over/(Under) Recovery to be Included in 2022 Rates	\$	(246,837,576)
3. Jurisdictional mWh Sales (Projected Period)	mWh	39,355,059
4. True-Up Factor (Line 2 / Line 3)	Cents/kWh	0.627

Duke Energy Florida, LLC
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors

Estimated for the Period of : January 2022 through December 2022

1. TOTAL AMOUNT OF ADJUSTMENTS:

A. Generating Performance Incentive Reward / (Penalty)	\$	2,657,279
B. True-Up (Over) / Under Recovery	\$	246,837,576
C. CEC Bill Credit	\$	11,109,749

2. JURISDICTIONAL mWh SALES	mWh	39,355,059
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3. ADJUSTMENT FACTORS:

A. Generating Performance Incentive Factor	Cents/kWh	0.007
B. True-Up Factor	Cents/kWh	0.627
C. CEC Bill Credit	Cents/kWh	0.028

Duke Energy Florida, LLC
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January 2022 through December 2022

1. Period Jurisdictional Fuel Cost (Schedule E-1, line 21)	\$	1,431,527,149
1a. Prior Period True-up (E1, Line 22)	\$	246,837,576
2. Generating Performance Incentive Factor (GPIF) (E1, Line 24)	\$	2,657,279
3. CEC Bill Credit	\$	<u>11,109,749</u>
4. Total Amount to be Recovered	\$	1,692,131,754
5. Jurisdictional Sales (January - December 2022)		39,355,059 mWh
6. Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)		4.300 Cents/kWh
7. Effective Jurisdictional Sales (See Below)		39,299,752 mWh

LEVELIZED FUEL FACTORS:

8. Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)	4.306 Cents/kWh
9. Fuel Factor at Primary Metering	4.263 Cents/kWh
10. Fuel Factor at Transmission Metering	4.220 Cents/kWh

TIERED FUEL FACTORS:

11. Fuel Factor - First Tier (0-1000 kWh)	3.995	Cents/kWh
12. Fuel Factor - Second Tier (Over 1000 kWh)	5.065	Cents/kWh

METERING VOLTAGE:	JURISDICTIONAL SALES (mWh)	
	METER	SECONDARY
Distribution Secondary	34,832,106	34,832,106
Distribution Primary	3,514,929	3,479,780
Transmission	<u>1,008,026</u>	<u>987,866</u>
Total	<u>39,355,061</u>	<u>39,299,752</u>

Duke Energy Florida, LLC
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January 2022 through December 2022

Line:	Metering Voltage	First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	-----Time of Use-----		
					On-Peak Multiplier 1.281	Off-Peak Multiplier 0.984	Super Off-Peak Multiplier 0.732
1.	Distribution Secondary	3.995	5.065	4.306	5.516	4.237	3.152
2.	Distribution Primary	--	--	4.263	5.461	4.195	3.121
3.	Transmission	--	--	4.220	5.406	4.152	3.089
4.	Lighting Service	--	--	3.991	--	--	--

Line 4 calculated at secondary rate of 4.306 * (13.2% * On-Peak Multiplier 1.281 + 48.6% * Off-Peak Multiplier 0.984 + 38.2% * Super Off-Peak Multiplier 0.732).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

ON-PEAK PERIOD				OFF-PEAK PERIOD				SUPER OFF-PEAK PERIOD				TOTAL	
Mo/Yr	System mWh Requirements	Marginal Cost	Average Marginal Cost (\$/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (\$/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (\$/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (\$/kWh)	
Jan-22	783,442	31,251,505	3.989	2,216,953	63,419,991	2.861	0	0	0.000	3,000,395	94,671,496	3.155	
Feb-22	704,914	27,139,194	3.850	1,956,339	55,501,386	2.837	0	0	0.000	2,661,253	82,640,580	3.105	
Mar-22	314,866	14,779,807	4.694	2,206,200	65,117,469	2.952	402,123	9,422,316	2.343	2,923,189	89,319,592	3.056	
Apr-22	323,207	11,829,358	3.660	2,278,968	57,882,289	2.540	365,467	7,267,516	1.989	2,967,641	76,979,163	2.594	
May-22	374,052	13,510,773	3.612	2,798,562	77,746,762	2.778	413,801	8,502,590	2.055	3,586,416	99,760,125	2.782	
Jun-22	434,821	14,379,524	3.307	3,025,507	86,746,636	2.867	515,356	10,535,077	2.044	3,975,684	111,661,237	2.809	
Jul-22	408,902	14,246,161	3.484	3,353,846	96,822,734	2.887	497,823	10,345,654	2.078	4,260,571	121,414,549	2.850	
Aug-22	467,055	14,576,778	3.121	3,245,263	94,449,368	2.910	560,614	11,539,707	2.058	4,272,932	120,565,853	2.822	
Sep-22	411,272	14,509,689	3.528	3,040,643	87,001,261	2.861	493,843	10,088,712	2.043	3,945,758	111,599,662	2.828	
Oct-22	347,783	13,302,689	3.825	2,667,038	73,438,937	2.754	413,368	8,369,080	2.025	3,428,189	95,110,707	2.774	
Nov-22	287,395	10,639,373	3.702	2,123,407	56,825,340	2.676	353,445	7,058,918	1.997	2,764,247	74,523,631	2.696	
Dec-22	773,407	23,975,612	3.100	2,162,087	49,948,456	2.310	0	0	0.000	2,935,494	73,924,068	2.518	
TOTAL	5,631,116	204,140,463	3.625	31,074,813	864,900,629	2.783	4,015,840	83,129,569	2.070	40,721,769	1,152,170,662	2.829	

MARGINAL FUEL COST
WEIGHTING MULTIPLIER

ON-PEAK
1.281

OFF-PEAK
0.984

OFF-PEAK
0.732

AVERAGE
1.000

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2022 through December 2022

		Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	TOTAL
1	Fuel Cost of System Net Generation	\$113,799,787	\$99,804,117	\$115,722,673	\$94,776,397	\$112,546,922	\$120,985,329	\$129,745,432	\$132,098,034	\$122,516,669	\$108,106,826	\$93,200,947	\$98,819,833	\$1,342,122,966
1a	Adjustments to Fuel Cost	1,058,537	872,354	1,051,635	1,048,289	1,045,151	1,041,699	1,038,142	1,034,690	1,031,238	1,027,889	1,024,026	1,020,780	12,294,429
2	Fuel Cost of Power Sold	(2,243,052)	(1,431,152)	(1,309,603)	(625,223)	(737,119)	(707,444)	(617,339)	(957,543)	(866,661)	(755,420)	(613,995)	(676,633)	(11,541,184)
2a	Gain on Total Power Sales - 20%	0	0	0	0	0	19,193	26,327	40,835	36,960	32,216	26,184	28,856	210,570
2b	Fuel Cost of Stratified Sales	(2,442,070)	(2,487,936)	(4,413,999)	(2,170,530)	(2,428,864)	(3,434,300)	(5,134,465)	(4,834,350)	(3,759,657)	(3,658,545)	(2,169,559)	(2,753,466)	(39,687,742)
3	Fuel Cost of Purchased Power (Excl Economy)	402,859	75,561	201,125	499,356	1,764,382	1,268,435	1,833,608	1,105,000	1,551,296	1,306,864	1,200,194	50,388	11,259,068
3a	Energy Payments to Qualifying Facilities	10,295,502	8,720,904	8,889,132	8,358,583	9,871,035	9,570,424	9,892,305	9,855,911	9,546,078	9,555,749	9,539,620	10,034,922	114,130,163
4	Energy Cost of Economy Purchases	255,518	244,320	496,365	153,968	213,081	162,977	226,632	242,983	248,573	281,761	225,562	221,401	2,973,141
5	Total System Fuel & Net Power Transactions	\$121,127,081	\$105,798,168	\$120,637,328	\$102,040,840	\$122,274,587	\$128,906,312	\$137,010,642	\$138,585,560	\$130,304,495	\$115,897,339	\$102,432,980	\$106,746,080	\$1,431,761,412
6	Jurisdictional mWh Sold	3,058,718	2,679,834	2,672,815	2,700,863	3,064,339	3,593,950	3,907,433	4,123,437	4,004,058	3,675,248	3,059,413	2,814,952	39,355,059
7	Jurisdictional % of Total Sales	99.98%	99.97%	99.98%	99.97%	99.94%	99.94%	99.95%	99.95%	99.95%	99.94%	99.98%	99.96%	99.96%
8	Jurisdictional Fuel & Net Power Transactions	121,102,855	105,766,429	120,613,200	102,010,227	122,201,223	128,828,969	136,942,137	138,516,267	130,239,343	115,827,801	102,412,493	106,703,381	1,431,164,325
9	Jurisdictional Loss Multiplier	1.00028	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	121,136,764	105,796,043	120,646,972	102,038,790	122,235,439	128,865,041	136,980,481	138,555,052	130,275,810	115,860,233	102,441,168	106,733,258	1,431,565,051
11	Adjusted System Sales	mWh 3,059,457	2,680,700	2,673,344	2,701,559	3,066,322	3,596,251	3,909,422	4,125,427	4,005,983	3,677,434	3,060,105	2,816,206	39,372,209
12	System Cost per kWh Sold	c/kWh 3.9591	3.9467	4.5126	3.7771	3.9876	3.5844	3.5046	3.3593	3.2527	3.1516	3.3474	3.7904	3.6365
13	Jurisdictional Loss Multiplier	x 1.00028	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 kWh Sold	c/kWh 3.9604	3.9479	4.5139	3.7780	3.9890	3.5856	3.5056	3.3602	3.2536	3.1524	3.3484	3.7917	3.6376
15	Prior Period True-Up	+ 0.6725	0.7676	0.7696	0.7616	0.6713	0.5724	0.5264	0.4989	0.5137	0.5597	0.6723	0.7307	0.6272
16	Total Jurisdictional Fuel Expense	c/kWh 4.6329	4.7154	5.2834	4.5396	4.6602	4.1580	4.0321	3.8590	3.7673	3.7121	4.0207	4.5224	4.2648
17	GPIF	+ 0.0072	0.0083	0.0083	0.0082	0.0072	0.0062	0.0057	0.0054	0.0055	0.0060	0.0072	0.0079	0.0068
18	CEC Bill Credit	+ 0.0000	0.0000	0.0132	0.0273	0.0507	0.0382	0.0349	0.0320	0.0307	0.0332	0.0338	0.0329	0.02823
19	Total Recovery Factor (rounded .001)	c/kWh 4.640	4.724	5.305	4.575	4.718	4.202	4.073	3.896	3.804	3.751	4.062	4.563	4.300

DEF's Response to Staff's 1st POD - Q1
Docket No. 20210001-EI
Alternative Schedule E10
Page 1 of 1

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Residential Bill Comparison

	Current Sep-Dec - 2021 (\$/1000 kWh)	Requested ¹ Average -2022 (\$/1000 kWh)	Difference from Current	
			\$	%
Base Rate ²	\$74.89	\$80.91	\$6.02	8.04%
Fuel Cost Recovery	32.28	39.95	7.67	23.76%
Capacity Cost Recovery (CCR) ³	14.05	11.55	(2.50)	-17.79%
Energy Conservation Cost Recovery (ECCR)	3.38	2.83	(0.55)	-16.27%
Environmental Cost Recovery (ECRC)	0.99	0.28	(0.71)	-71.72%
Storm Protection Plan Cost Recovery Charge (SPPCRC)	0.31	3.29	2.98	961.29%
Interim Storm Charge ⁴	0.55	0.85	0.30	54.55%
Asset Securitization Charge (ASC)	2.48	2.48	0.00	0.00%
Subtotal	128.93	142.14	13.21	10.25%
Gross Receipts Tax and Regulatory Assessment Fee ⁵	3.31	3.75	0.44	13.29%
Total	<u>\$132.24</u>	<u>\$145.89</u>	<u>\$13.65</u>	<u>10.32%</u>

¹ For 2022, reflects the average bill impact for a Residential customer using 1,000 kWh.

² Base Rate is in accordance with the 2021 Settlement Agreement approved in Order No. PSC-2021-0202-AS-EI.

³ If the Commission were to deny the Rate Mitigation Plan, DEF would still propose treating the SoBRA adjustments in the same manner, which has a (\$0.26) impact on the 2022 CCR average.

⁴ The 2022 average interim storm charge includes Hurricanes Eta & Isaias, as approved in Order No. PSC-2021-0271-PCO-EI and an estimate for Hurricane Elsa. The included Hurricane Elsa estimated impact of \$0.53 to the 2022 Interim Storm Charge average, based on an \$18 million storm cost estimate, effective with Jan-2022 billing.

⁵ Per the 2021 Settlement Agreement, the Regulatory Assessment Fee (RAF) has been removed from base rates and recovery clauses and included on customer bills on the same line as Gross Receipts Tax beginning with January 2022 billing.

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Calculation of Inverted Residential Fuel Factors

	Annual Units mWh	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues	Inverted Fuel Rates Cents/kWh	Annual Fuel Revenues
Residential Excluding TOU:					
0 - 1,000 kWh	13,066,657	4.306	\$ 562,650,236	3.995	\$ 522,005,710
Over 1,000 kWh	5,355,406	4.306	230,603,785	5.065	271,248,356
Total	<u>18,422,062</u>		<u>\$ 793,254,021</u>		<u>\$ 793,254,066</u>
Rate Differential by Tier - Cents per kWh				1.070	
Residential Sales:					
Total	21,211,129				
Time of Use	<u>2,789,068</u>				
Levelized	<u>18,422,062</u>				

DEF's Responses to Staff's Fifth Set of Interrogatories, Nos. 8-14.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 20210001-EI

Dated: October 13, 2021

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 8-14)**

Duke Energy Florida, LLC ("DEF") responds to the Staff of the Florida Public Service Commission ("Staff") Fifth Set of Interrogatories (Nos. 8-14) as follows:

INTERROGATORIES

8. Please refer to DEF witness Dean's actual/estimated testimony filed on July 27, 2021, Page 4, Line 21 through Page 5, Line 2.
- a. Please provide the amount of repair costs associated with the Crystal River 4 outage. As a part of this response categorize all necessary repairs with their costs.

Response:

This question is outside the scope of Docket No. 20210001 since it refers to repair costs which are a base rate matter. DEF is not collecting, or proposing to collect, the repair costs through the fuel clause.

9. Please refer to DEF witness Lewter's direct testimony filed on March 16, 2021, Page 4, Lines 1 – 7 and Exhibit MIL-1T, Page of 2 of 22. Please provide the Generation Performance Incentive Factor (GPIF) penalty associated the Crystal River 4 outage.

Response:

DEF witness Lewter's direct testimony filed on March 16, 2021, and the associated Exhibit MIL-1T provide the Generating Performance Incentive Factor (GPIF) reward amount and supporting schedules for the period of January through December 2020. Crystal River 4

was not included in the GPIF program during this time period and, as such, a penalty is not applicable for this unit.

10. Please refer to DEF's Response to OPC's 1st Set of Interrogatories, No. 6 and DEF witness Simpson's actual/estimated testimony filed on July 27, 2021, Exhibit JS-1, page 2 of 9. Was DEF's Citrus combined-cycle power plant outage included in the Crystal River 4 replacement power calculation? If not, provide replacement power costs with the inclusion of the Citrus combined-cycle power plant outage.

Response:

No. The Citrus CC outage was not included in the CR4 replacement power calculation. Citrus CC was down less than 13 hours and any associated replacement power costs are negligible.

11. Please refer to DEF witness Simpson's actual/estimated testimony filed on July 27, 2021, Page 7, Lines 3 -4.
 - a. Provide the operator's experience and training regarding power plant operations.

Response:

The Operator was an apprentice at Crystal River South (CRS - Units 1 and 2) in 2006, and became a journeyman in 2010. The Operator was then at Crystal River North (CRN - Units 4 and 5) from 2010-2013, then back at CRN in 2017. From 2013-2017, the operator was employed with another utility performing similar work.

- b. Provide the operator's training history. As a part of this response, provide the last time the operator was trained in manual synchronization.

Response:

Please see the training record bearing bates numbers 20210001-DEF-000075 through 20210001-DEF-000086. Trainings which may have included generator operation and synchronization are highlighted. There is not a specific training

course for "Generator Synchronization". On the Job Training (OJT) is not specifically documented nor are simulator sessions.

For the following questions please refer to witness Simpson's actual/estimated testimony Exhibit JS-1, Root Cause Analysis Report filed on July 27, 2021.

12. Please refer to page 2 of 9 of Exhibit JS-1.

- a. Explain the proper procedure for operators to follow after a failed auto synchronization attempt. As a part of this response, explain if there are separate procedures for multiple failed auto synchronization attempts.

Response:

There are several plausible failure modes (failure of voltage matching, system voltage outside of sync window, generator voltage outside of sync window, failure of speed/frequency controls, etc.) so a procedure encompassing all credible failure modes would be prohibitively difficult to develop, and offering an opinion on all proper steps to follow without understanding what failure mode led to the failed synchronization and other variables at play in a given situation would require a large amount of speculation. That said, following a failed synchronization attempt, the standard procedure for the operators would be to perform a walkdown to inspect the various potential failure modes in turn; if an issue is discovered, it is corrected, the system is reset, and synchronization is attempted again. If that attempt fails, the process begins again until synchronization is completed. During this process, proper breaker control handle position (green or red flag) should be observed . Since the time of this event, as discussed in response to 14a, below, the start-up procedures have since been revised and now include a requirement to inform the Operations Superintendent or Plant Manager in the event of multiple failed syncs.



- b. When, and under what circumstances, was the last instance that manual synchronization was utilized at Crystal River 4?

Response:

There is not a specific entry in DEF's records that indicate which method was used for each synchronization event. Since both methods are procedurally permitted (and have always been procedurally permitted) there would not be anything that kept track of normal procedural conformance.

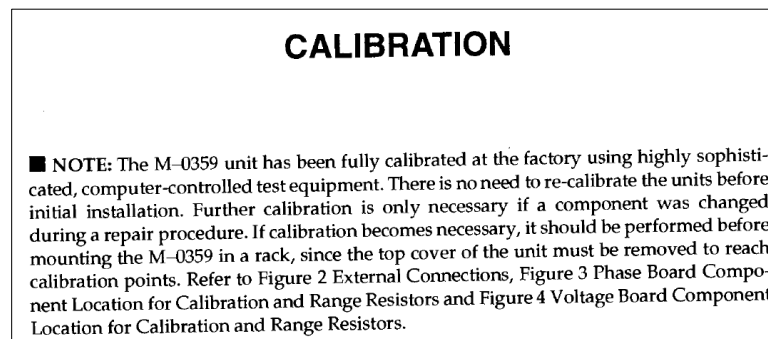
Since the event, there have been several successful manual synchronizations, including post maintenance testing and performance of corrective actions in the RCA. As recently as July 16, 2021, a manual synchronization was performed for purposes of observation on the job training of newly hired Operators.

13. Refer to page 3 of 9 of Exhibit JS-1.

- a. Provide a list of inspection dates for Manual Sync Check Relay model M-0359 (25A1) serial #1711. As a part of this response, provide the maintenance interval for this equipment.

Response:

Please see accessible calibrations from 2011, 2014, 2018, and 2020, bearing bates numbers 20210001-DEF-000087 through 20210001-DEF-000144.



The M-0359 is a non-NERC BES component, meaning it is not required to be tested on the 6-year time frame mandated by NERC; notwithstanding, the component has been calibrated more frequently than NERC would have required, and more often than the manufacturer recommends.

- b. Detail the typical life expectancy for a Manual Sync Check Relay model M-0359.

Response:

There is no manufacturer published life expectancy for M-0359.

- c. Explain why the Operations Team Supervisor did not inform the operators of the modified relay panels.

Response:

It is unknown why this specific OTS did not have this specific conversation with the on-shift crew. The line relay panels have a laminated guide affixed to the panel as a job aid to assist with reset process.



- d. Provide a full timeline of Crystal River Unit 4 outage event.

Response:

Refer to RCA Section II for timeline up to January 7th. Additional CR4 milestone dates associated with generator outage are as follows.

January 7th - 19th: Lock Out Tag Out, Partial Disassembly, Inspect, Test Rotor

January 21st: Rewind Determination Completed and Contract Evaluation/Selection

January 26th: Generator Disassembly

January 28th: Rotor Shipment to St. Louis facility

February 4th - March 8th: Rotor Repairs in St. Louis facility

March 8th: Ship rotor from St. Louis back to Crystal River

March 15th - March 21st: Generator Reassembly and Restoration

March 22nd/23rd - Unit 4 Startup

March 25th 06:05 AM: Unit 4 Synchronized to Grid (in AUTO Sync Mode)

14. Please refer to page 4 of 9 Exhibit JS-1.

- a. Refer to Contributing Cause A3B3C06. Explain if contacting the Operations Superintendent and/or Station Manager was the proper procedure at the time of the incident. As a part of this response explain if this has changed since the time of the incident.

Response:

Contacting Operations Superintendent and/or Station Manager was not part of OI-1 (Startup Procedure) at the time of the event. At the time of the event, the governing revision was Revision 12 (Issued May 2020).

Since this event, Revision 13 has been revised to include guidance/steps for failure of expected breaker closure response as part of 13.2.1.7 and its associated substeps.

_____ 13.2.1.7	<u>IF</u> closing the generator breaker on unit 4, <u>THEN</u> RED FLAG SET (CLOSE) generator output breaker 3233 or 3234 <u>WHEN</u> the sync scope is as the 11 o'clock position. (The amber light will energize because the flag is set, but the breaker has not been closed by the relay yet. Red flag setting the output breaker control handle will send a signal to the relay to close breaker 3233 or 3234).			
_____ A.	VERIFY that the relay closes in the selected generator breaker.			
1. <u>IF</u> breaker fails to close on first attempt, then perform the following: a. INCREASE OR DECREASE voltage to better match system voltage. b. INCREASE OR DECREASE turbine speed by one or two rpm (based on speed of sync scope rotation). 2. <u>IF</u> breaker fails to close after performing the above steps, <u>THEN</u> contact the Operations Superintendent a. <u>IF</u> the Operations Superintendent is unavailable, <u>THEN</u> contact the Plant Manager.				
<table style="width: 100%; border: none;"> <tr> <td style="border: none; text-align: center;"> _____ Person Notified </td> <td style="border: none; text-align: center;"> _____ Date </td> <td style="border: none; text-align: center;"> _____ Time </td> </tr> </table>		_____ Person Notified	_____ Date	_____ Time
_____ Person Notified	_____ Date	_____ Time		

- b. Refer to Contributing Cause A5B2C08. Explain why Enclosure 5 of the Start-Up Procedure was incomplete.

Response:

The procedure contained all relevant information, it was only incomplete in the sense it did not direct the operator back to the main body of the procedure after completing Enclosure 5.

That is, Rev. 12, procedure step 13.2, directed the Operator to Enclosure 5 for Manual Sync guidance, but did not then direct the operator back to the main body of the procedure, which completes the manual synchronization steps. Rev 13 of the procedure has been issued to increase usability of these sections as a corrective action stemming from this event.

- c. Refer to Contributing Cause A485C09. Explain why the laminated generator synchronizing guidance (operator aid) did not exist for unit 4.

Response:

DEF believes the disparity is due to the differences between Units 4 and 5. The laminated operator aid for Unit 5 addressed major modifications to Unit 5 (made during substation modernization activities in 2017) which reduced the Unit to single generator output breaker configuration and also removed the capability for Unit 5 to be manually synchronized). The purpose of the laminated operator aid was likely to assist Unit 5 Operators to understand the effects of those differences. The Unit 4 substation modernization was unlike the Unit 5 substation modernization in that it did not change the number of output breakers or the available synchronization methods (AUTO or MANUAL), so therefore no interim description or operational change was required to be communicated to the Operators.

20210001.EI Staff Hearing Exhibits 00052

Training Code	Title	Type	Last Completion Date
TRF006-N 00000-N	TRF006-N 00000-N Sec	ILT Class	6/1/2001
TRF007-N 00000-N	TRF007-N 00000-N Sec	ILT Class	9/1/2001
TRF008-N 00000-N	TRF008-N 00000-N Sec	ILT Class	12/1/2001
TRF001-N 00000-N	TRF001-N 00000-N Sec	ILT Class	3/1/2002
TRF002-N 00000-N	TRF002-N 00000-N Sec	ILT Class	6/1/2002
TRF003-N 00000-N	TRF003-N 00000-N Sec	ILT Class	9/1/2002
GNB0001C-N 0042-N	GNB0001C-N 0042-N C	ILT Class	11/26/2002
TRF004-N 00000-N	TRF004-N 00000-N Sec	ILT Class	12/1/2002
GNB01N-N	GNB01N-N PLANT ACC	eLearning	12/16/2002
FWB01G-N	FWB01G-N HOT WORK	eLearning	12/17/2002
GNB02N-N	GNB02N-N RAD WORK	eLearning	12/17/2002
ST0029-N	ST0029-N CR3 FIREWA	eLearning	12/17/2002
ST0055CB-N	ST0055CB-N FOREIGN	eLearning	12/17/2002
ST1171CB-N	ST1171CB-N CONFINE	eLearning	12/17/2002
TSM015CB-N	TSM015CB-N Self Chec	eLearning	12/18/2002
ADC0216-N 0001-N	ADC0216-N 0001-N Ze	ILT Class	12/23/2002
ADC0216-N	ADC0216-N Zero Energ	ILT Course	12/23/2002
ST1263-N 0009-N	ST1263-N 0009-N Cr3	ILT Class	2/6/2003
TRF005-N 00000-N	TRF005-N 00000-N Sec	ILT Class	3/1/2003
ADC0219C-N 0001-N	ADC0219C-N 0001-N H	ILT Class	3/13/2003
ADC0219C-N	ADC0219C-N Hands Sa	ILT Course	3/13/2003
TRF000-N 0312-N	TRF000-N 0312-N Initi	ILT Class	3/14/2003
TRF000-N	TRF000-N Initial Fire	ILT Course	3/14/2003
TRF006-N 0088-N	TRF006-N 0088-N Sect	ILT Class	6/19/2003
TRF007-N 0081-N	TRF007-N 0081-N Sect	ILT Class	7/24/2003
GNI0004C-N 0012-N	GNI0004C-N 0012-N CI	ILT Class	9/5/2003
GNI0004C-N	GNI0004C-N CR3 Safet	ILT Course	9/5/2003
ME03G	SNORKEL LIFT/AERIAL	ILT Course	12/7/2003
TRF008-N 0083-N	TRF008-N 0083-N Sect	ILT Class	12/8/2003
SF2085	EMERGENCY RESPON	ILT Course	12/15/2003
SF105	HAZARD COMMUNICA	ILT Course	12/15/2003
SF113	PERSONNEL PROTECTI	ILT Course	12/15/2003
SF983	SAFETY SIGNS AND TA	eLearning	12/15/2003
SF550	Stairways and Ladders	eLearning	12/15/2003
SF155-N	SF155-N Bloodborne P	eLearning	12/16/2003
MD152_P	Diversity Non Supervi	ILT Course	12/18/2003
MD152_P 0267	Diversity Non Supervi	ILT Class	12/18/2003
GNICS02C-N 0001-N	GNICS02C-N 0001-N S	ILT Class	1/6/2004
GNICS02C-N	GNICS02C-N SAF-NGG	ILT Course	1/6/2004
MEC0002C-N 0011-N	MEC0002C-N 0011-N 1	ILT Class	1/8/2004
MEC0002C-N	MEC0002C-N 1st Qtr 2	ILT Course	1/8/2004
TRF001-N 0099-N	TRF001-N 0099-N Sect	ILT Class	2/25/2004
ENC0010G	ENV EXCELLENCE POLI	ILT Course	4/5/2004
ST1263-N 0017-N	ST1263-N 0017-N Cr3	ILT Class	4/22/2004

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20210001.EI Staff Hearing Exhibits 00053

TRFA-N 0166-N	TRFA-N 0166-N Fire Br ILT Class	6/3/2004
TRF002-N 0112-N	TRF002-N 0112-N Sect ILT Class	6/14/2004
MEC0003C-N 0002-N	MEC0003C-N 0002-N 2 ILT Class	6/18/2004
MEC0003C-N	MEC0003C-N 2nd Qtr : ILT Course	6/18/2004
MTSA01	MTSA Familiarization ILT Course	6/22/2004
ORR0012F	RR Op & Safety Cert R ILT Course	7/25/2004
ORR0012F 0017	RR Op & Safety Cert R ILT Class	7/25/2004
TRF002-N 0129-N	TRF002-N 0129-N Sect ILT Class	9/30/2004
TRF003-N 0102-N	TRF003-N 0102-N Sect ILT Class	9/30/2004
ISD8024A	CLEARANCE AWARENE ILT Course	10/13/2004
EHSPST	Plant S&T-part B Site S ILT Course	10/13/2004
EHSPST03-N 00000-N	EHSPST03-N 00000-N I ILT Class	10/14/2004
EHSPST03-N	EHSPST03-N Plant S&T ILT Course	10/14/2004
OPI1301N-N 00000-N	OPI1301N-N 00000-N I ILT Class	10/14/2004
OPI1301N-N	OPI1301N-N INITIAL CI ILT Course	10/14/2004
ADMFGD37	Conduct of Material H eLearning	11/9/2004
ITF0080G-N	ITF0080G-N PassPort F eLearning	11/10/2004
ITF0081G-N	ITF0081G-N PassPort F eLearning	11/10/2004
ITF0082G-N	ITF0082G-N PassPort F eLearning	11/10/2004
ITF0083G-N	ITF0083G-N PassPort F eLearning	11/10/2004
ORI0022F	Rail Incident Preventic eLearning	11/29/2004
TRF004-N 0069-N	TRF004-N 0069-N Sect ILT Class	12/13/2004
TRF004-N	TRF004-N SECTION 4- I ILT Course	12/13/2004
GNI0002N-N	GNI0002N-N CONFINE eLearning	12/15/2004
SFI0001N-N	SFI0001N-N SCWE - IN eLearning	12/15/2004
TRF005-N 0085-N	TRF005-N 0085-N Sect ILT Class	1/6/2005
GNI0005N-N	GNI0005N-N CLEARAN eLearning	2/6/2005
TRFA-N 00000-N	TRFA-N 00000-N Fire E ILT Class	2/23/2005
TRFA-N	TRFA-N FIRE BRIGADE ILT Course	2/23/2005
TRF005-N 0091-N	TRF005-N 0091-N Sect ILT Class	2/25/2005
TRF005-N	TRF005-N SECTION 5- I ILT Course	2/25/2005
ST0003-N 0177-N	ST0003-N 0177-N How ILT Class	3/28/2005
ST0003-N	ST0003-N How & Why ILT Course	3/28/2005
ST1263-N 0030-N	ST1263-N 0030-N Cr3 I ILT Class	3/29/2005
MTC052C-N 0004-N	MTC052C-N 0004-N CF ILT Class	4/7/2005
MTC052C-N	MTC052C-N CR3 Main' ILT Course	4/7/2005
TRF006-N 0094-N	TRF006-N 0094-N Sect ILT Class	4/18/2005
TRF006-N	TRF006-N SECTION 6- I ILT Course	4/18/2005
ITF0069N-N 0003-N	ITF0069N-N 0003-N PV ILT Class	5/9/2005
ITF0069N-N	ITF0069N-N PVX Wk M ILT Course	5/9/2005
LD250	Peer Leadership Progr: ILT Course	6/22/2005
LD250 0127	Peer Leadership Progr: ILT Class	6/22/2005
OPR1301N-N	OPR1301N-N CLEARAN eLearning	7/5/2005
GNB0001C-N 00000-N	GNB0001C-N 00000-N ILT Class	7/15/2005
ST0001-N 0151-N	ST0001-N 0151-N Cran ILT Class	7/21/2005

20210001.EI Staff Hearing Exhibits 00054

ST0001-N	ST0001-N CRANE TRAI	ILT Course	7/21/2005
MNC0503C-N 0009-N	MNC0503C-N 0009-N	: ILT Class	8/1/2005
MNC0503C-N	MNC0503C-N 3rd Qtr	: ILT Course	8/1/2005
TRF007-N 0096-N	TRF007-N 0096-N Sect	ILT Class	8/5/2005
TRF007-N	TRF007-N SECTION 7-	ILT Course	8/5/2005
GNB0001C-N 0635-N	GNB0001C-N 0635-N C	ILT Class	8/12/2005
GNB0001C-N	GNB0001C-N Crystal R	ILT Course	8/12/2005
MEI01N-N 0045-N	MEI01N-N 0045-N Sca	ILT Class	8/18/2005
MEI01N-N	MEI01N-N SCAFFOLDI	ILT Course	8/18/2005
MNI0001C-N 0002-N	MNI0001C-N 0002-N R	ILT Class	9/15/2005
MNI0001C-N	MNI0001C-N CR3 RCA	ILT Course	9/15/2005
GNI0001N-N	GNI0001N-N FOREIGN	eLearning	12/13/2005
GNR01N-N	GNR01N-N PLANT ACC	eLearning	12/13/2005
GNR02N-N	GNR02N-N RAD WORK	eLearning	12/13/2005
ST1160CB-N	ST1160CB-N SAFETY A`	eLearning	12/13/2005
TRF008-N 0094-N	TRF008-N 0094-N Sect	ILT Class	12/16/2005
TRF008-N	TRF008-N SECTION 8-	ILT Course	12/16/2005
WLI0007N-N 0025-N	WLI0007N-N 0025-N N	ILT Class	1/30/2006
WLI0007N-N	WLI0007N-N NGG WM	ILT Course	1/30/2006
SFQ0002G	SFQ0002G - SCBA Fit T	ILT Course	2/1/2006
SFQ0005G	SFQ0005G - MSA Full F	ILT Course	2/1/2006
GN6C11C-N 0106-N	GN6C11C-N 0106-N CF	ILT Class	2/2/2006
GN6C11C-N	GN6C11C-N CR3 RESPI	ILT Course	2/2/2006
MNC061C-N 0005-N	MNC061C-N 0005-N C	ILT Class	2/16/2006
MNC061C-N	MNC061C-N CR3 Main	ILT Course	2/16/2006
SFI0004N-N	SFI0004N-N MEDICAL	eLearning	2/27/2006
SFI0021G-N	SFI0021G-N MEDICAL-	eLearning	2/27/2006
TRF001-N 0115-N	TRF001-N 0115-N Sect	ILT Class	2/27/2006
TRF001-N	TRF001-N SECTION 1-	ILT Course	2/27/2006
ST1263-N 0039-N	ST1263-N 0039-N Cr3	ILT Class	3/21/2006
ST1263-N	ST1263-N CR3 MSSV G	ILT Course	3/21/2006
TRF002-N 0133-N	TRF002-N 0133-N Sect	ILT Class	6/30/2006
TRF002-N	TRF002-N SECTION 2-	ILT Course	6/30/2006
TRF003-N 0108-N	TRF003-N 0108-N Sect	ILT Class	8/16/2006
TRF003-N	TRF003-N SECTION 3-	ILT Course	8/16/2006
TRST1008 0058	P&id Print Reading	ILT Class	11/5/2006
TRST1008	TRST1008 - Print Read	ILT Course	11/5/2006
IT000002	Basic Computer Skills	ILT Course	11/6/2006
IT000002 0165	Basic Computer Skills	ILT Class	11/6/2006
TRST1056	Basic Technical Math	ILT Course	11/6/2006
TRST1056 0020	Basic Technical Math	ILT Class	11/6/2006
MEI0022G	MEI0022G - Valves Op	ILT Course	11/7/2006
MEI0022G 0037	Valves Operation Trair	ILT Class	11/7/2006
EHSEQ10 0031	Hand Tool Safety	ILT Class	11/8/2006
EHSEQ10	HAND TOOL SAFETY -	ILT Course	11/8/2006

20210001.EI Staff Hearing Exhibits 00055

MEB01G-N 0040-N	MEB01G-N 0040-N Ba: ILT Class	11/9/2006
MEB01G-N	MEB01G-N Basic Gene ILT Course	11/9/2006
TRST7011 0135	Pwr Plt Steam & Mech ILT Class	11/15/2006
TRST7011	TRST7011 - Power Plar ILT Course	11/15/2006
TRST7075	Bearings And Lubricati ILT Course	11/20/2006
TRST7075 0031	Bearings And Lubricati ILT Class	11/20/2006
TRST7074	Mechanical Drives, Co ILT Course	11/20/2006
TRST7074 0024	Mechanical Drives, Co ILT Class	11/20/2006
TRST1051	Basic Electricity ILT Course	11/27/2006
TRST1051 0028	Basic Electricity ILT Class	11/27/2006
TRST7070	Measuring Instrument ILT Course	11/28/2006
TRST7070 0044	Measuring Instrument ILT Class	11/28/2006
POC0001G 0024	Breaker Operations ILT Class	11/29/2006
POC0001G	POC0001G - Breaker Fi ILT Course	11/29/2006
POI0002F 0028	Intro to Power Genera ILT Class	2/8/2007
POI0002F	POI0002F - Intro to Po ILT Course	2/8/2007
POQ0003F	Fos Clear/S&T Hanger eLearning	3/12/2007
OPI1301F	PVX S&T/Tag Out for I eLearning	3/12/2007
SEI0002G	MTSA Critical Staff Tra ILT Course	4/22/2007
SEI0002G 0005	MTSA Critical Staff Tra ILT Class	4/22/2007
PO0018F	Surviving Combustion ILT Course	6/10/2007
PO0018F 0017	Surviving Combustion- ILT Class	6/10/2007
SF190 4888	American Heart CPR/F ILT Class	8/6/2007
SF190	American Heart CPR/F ILT Course	8/6/2007
HS0277	EHST - CPR /AED/ First ILT Course	8/7/2007
HS0276	EHST - CPR/AED/First / ILT Course	8/7/2007
SF191-N 00000-N	SF191-N 00000-N AmF ILT Class	8/7/2007
SF191-N	SF191-N AMERICAN HI ILT Course	8/7/2007
FRM470 0433	ES Annual Inspection C ILT Class	9/11/2007
TRST1035	Turbine Generator Tra ILT Course	9/27/2007
TRST1035 0090	Turbine Generator Tra ILT Class	9/27/2007
TRST1039	Electrical System Train ILT Course	10/4/2007
TRST1039 0032	Electrical System Train ILT Class	10/4/2007
ITF0123G-N	ITF0123G-N IT&T Secu eLearning	12/18/2007
SFI0050G	DRUG, ALCOHOL AND ILT Course	12/21/2007
CEMS12	FGD CEMS Op training ILT Course	2/25/2008
CEMS12 0005	FGD CEMS Op training ILT Class	2/25/2008
EHS0009 0214	Fixed Fire Exting Sys ILT Class	3/1/2008
EHS0009	FIXED FIRE EXTING SYS ILT Course	3/1/2008
LET01G	Lead Awareness Traini ILT Course	3/9/2008
ME07G	SCAFFOLD USER TRAIN ILT Course	3/9/2008
SF2069	SF2069 - Flyash Protec ILT Course	3/12/2008
TRST7115	Digital Control System: ILT Course	4/24/2008
TRST7115 0023	Digital Control System: ILT Class	4/24/2008
MM155GH	FORKLIFT RETRAINING ILT Course	5/19/2008

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DE-103727	EHST - Order Picker Ini eLearning	5/20/2008
DE-103728	EHST - Stand-up Reach eLearning	5/20/2008
HS0900P-N 00000-N	HS0900P-N Fork Lift Pr ILT Class	5/20/2008
MM155G-N	MM155G-N FORKLIFT eLearning	5/20/2008
SEC0002	NERC Reliability Stds - eLearning	6/16/2008
ITF0126G-N 00000-N	ITF0126G-N 00000-N I' ILT Class	8/16/2008
ITF0126G-N	ITF0126G-N IT&T Secu ILT Course	8/16/2008
EL0018G 0081	Arc Flash PPE - Interim ILT Class	9/8/2008
EL0018G	EL0018G -Arc Flash PP ILT Course	9/8/2008
ADIFGD26	FGD Conduct of Oper: ILT Course	9/19/2008
ADIFGD26 0010	FGD Conduct of Oper: ILT Class	9/19/2008
SFQ0001G	SFQ0001G - 3M HALF I ILT Course	9/30/2008
FOS001CR	FOS001CR - Simulator ILT Course	10/9/2008
FOS001CR 0014	Simulator Startup & S ILT Class	10/9/2008
ORI0018F	Ash Handling Truck Op ILT Course	11/30/2008
ME82G	Bottom Ash Shot Gun ILT Course	12/16/2008
SF478P 0054	Fire Extinguisher Pract ILT Class	3/8/2009
SFI000CG-N	SFI000CG-N QUALIFIE eLearning	5/28/2009
SFI000EG-N	SFI000EG-N QUALIFIE eLearning	5/28/2009
SFI000LG-N	SFI000LG-N QUALIFIE eLearning	5/28/2009
SFI000NG-N	SFI000NG-N QUALIFIE eLearning	5/28/2009
SFI000PG-N	SFI000PG-N QUALIFIE eLearning	5/28/2009
SFI000SG-N	SFI000SG-N QUALIFIE eLearning	5/28/2009
SFI0020G-N	SFI0020G-N MEDICAL- eLearning	5/28/2009
SFI0022G-N	SFI0022G-N HALF FACI eLearning	5/28/2009
SFI0023G-N	SFI0023G-N MEDICAL- eLearning	5/28/2009
SFI0024G-N	SFI0024G-N TOTAL EXF eLearning	5/28/2009
SFI0025G-N	SFI0025G-N MEDICAL I eLearning	5/28/2009
DIVEW01 0228	Business Case for Dive ILT Class	7/7/2009
DIVEW01	Business Case for Dive ILT Course	7/7/2009
DIVEW04	Generations in the Wc ILT Course	7/7/2009
POQ0004F	PVX Tag Out for Clear I eLearning	7/29/2009
ENC002CR	Crystal River Oil Spill T eLearning	9/15/2009
SF149 0259	Am Heart/ASHI Adult I ILT Class	10/20/2009
SF149	Legacy Progress CPR & ILT Course	10/20/2009
SEC0001 0203	NERC Personnel Risk A ILT Class	10/27/2009
EL0018I	EL0018I - Arc Flash Init ILT Course	2/1/2010
EL0018P	EL0018P - Arc Flash Tr: ILT Course	2/1/2010
ENC0013G	STORMWATER POLLU' ILT Course	2/14/2010
TR000179	DEFENSIVE DRIVING eLearning	6/3/2010
SF225PV	DEFENSIVE DRIVING IN ILT Course	6/3/2010
DIVEW02	Exploring Differences i ILT Course	8/2/2010
DIVEW02 0624	Exploring Differences i ILT Class	8/2/2010
DIVEW05	Subtle Behaviors ILT Course	8/2/2010
DIVEW05 0565	Subtle Behaviors for Ei ILT Class	8/2/2010

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ITI003F	Non-sup Auto roster c: ILT Course	8/15/2010
EHSELE03-N	EHSELE03-N Electrical eLearning	9/21/2010
ETHICS10	Ethics In Action CBT 2C ILT Course	9/21/2010
EHSELE01	ELECTRICAL SAFETY Av ILT Course	9/22/2010
RESPP-N	RESPP-N Respirator Pr ILT Course	9/23/2010
SF478P 0105	Fire Extinguisher Pract ILT Class	9/28/2010
SF2118	CONFINED SPACE AW/ ILT Course	9/29/2010
GN6C100N-N	GN6C100N-N POG COI eLearning	9/30/2010
EHSRAD01	Radiation Safety Traini ILT Course	9/30/2010
FRM470 0606	ES Annual Inspection C ILT Class	11/3/2010
EV617CR4 0001	Spill Prevention C&C - ILT Class	11/25/2010
HR0004F 0056	Anatomy of an Event - ILT Class	11/30/2010
CRFO001 0005	CR Scrubber Steam Op ILT Class	12/5/2010
CRFO001	CR Scrubber Steam Op ILT Course	12/7/2010
CRFO001 0006	CR Scrubber Steam Op ILT Class	12/7/2010
CRFH001	Crystal River Flyash Sy: ILT Course	12/7/2010
CRFH001 0003	Crystal River Flyash Sy: ILT Class	12/7/2010
EN0102	90/180 Day/TSDf Stor: eLearning	2/13/2011
EV639CR	EV639CR - RCRA SMAL ILT Course	2/13/2011
EN0100	Introduction to Hazarc eLearning	2/13/2011
EN0118	Moving Hazardous Stu eLearning	2/13/2011
EN0101	Satellite Accumulation eLearning	2/13/2011
EV601GZ-N	EV601GZ-N DOT Spec` eLearning	2/14/2011
CRNHPI02 0001	CRN HPI Electronic Tag ILT Class	2/14/2011
HR0004F	Anatomy of an Event - ILT Course	3/20/2011
HR0004F 0058	Anatomy of an Event - ILT Class	3/20/2011
CRNS01	CRN Boiler Bypass Syst ILT Course	3/21/2011
CRNS01 0003	CRN Boiler Bypass Syst ILT Class	3/21/2011
CRNHPI02	CRN HPI Electronic Tag ILT Course	3/21/2011
CRNHPI02 0005	CRN HPI Electronic Tag ILT Class	3/21/2011
CRNS02	CRN Feedwater Contrc ILT Course	3/22/2011
CRNS02 0002	CRN Feedwater Contrc ILT Class	3/22/2011
CRNYCON	CRN Cond. Clean. Beal ILT Course	3/23/2011
CRNYCON 0002	CRN Cond. Clean. Beal ILT Class	3/23/2011
CRNYPID	CRN P&ID Redlining ILT Course	3/23/2011
CRNYPID 0001	CRN P&ID Redlining ILT Class	3/23/2011
NGSAF01	Gas Safety Awareness eLearning	6/18/2011
ETHCS11C	Ethics In Action CBT 2C ILT Course	6/26/2011
LD199B	Culture in Action CBT ILT Course	7/24/2011
VAR002C	NERC VAR002 Complia eLearning	7/26/2011
CRNTRANS	Transformer Oper. Rev ILT Course	9/11/2011
CRNTRANS 0002	Transformer Oper. Rev ILT Class	9/11/2011
CRNTUROP	Turbine Retrofit / Loac ILT Course	9/12/2011
CRNTUROP 0001	Turbine Retrofit / Loac ILT Class	9/12/2011
ME105PV	Intrinsically Safe Equip eLearning	12/11/2011

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SF478P 0160	Fire Extinguisher Pract	ILT Class	2/28/2012
MNI0011G	Alr Compressor/Dessic	ILT Course	3/4/2012
MNI0012G	Precipitator Controls	ILT Course	3/4/2012
MNI0013G	EHC Front Standard/Pi	ILT Course	3/5/2012
MNI0014G	Generator Core Monit	ILT Course	3/5/2012
MNI0015G	CCM Refresher	ILT Course	3/6/2012
OPR1302F	OPR1302F - Contracto	ILT Course	3/6/2012
SF2124	SF2124 - Defensive Dri	ILT Course	3/7/2012
SF2124 0019	Smith Driving Classroo	ILT Class	3/7/2012
HS2124	Smith System Driver C	ILT Course	3/7/2012
PMC-001 COT148C	NO NOT USE THIS COL	eLearning	3/8/2012
HS2125	Smith System Driver P	ILT Course	3/8/2012
SFI0206G	SFI0206G FALL PROTE	ILT Course	3/21/2012
EV601G-N	EV601G-N DOT GEN A	eLearning	3/22/2012
TR000170	ACCESS TO MEDICAL R	eLearning	3/25/2012
TR400446	POG Interface Agree-F	eLearning	3/25/2012
TR400460	TRM I A for Pwr Gen F	eLearning	3/25/2012
OPR1301F	PVX S&T/Tag Out for	eLearning	3/26/2012
EV617CR1	Spill Prevention C&C	- ILT Course	4/21/2012
EV617CR4	Spill Prevention C&C	- ILT Course	4/21/2012
SFI0026G-N	SFI0026G-N AUDIOGR	eLearning	5/31/2012
EL0018R	EL0018R - ARC FLASH	ILT Course	8/26/2012
SFI0031G-N	SFI0031G-N HEXAVALE	eLearning	8/27/2012
CRMAGORI	Magnetrol Orion Auro	ILT Course	9/26/2012
CRMAGORI 0002	Magnetrol Orion Auro	ILT Class	9/26/2012
SF459	ASBESTOS AWARENES	ILT Course	10/5/2012
EC10612	COBE Refresher 2012	eLearning	10/19/2012
FRM470 0687	ES Annual Inspection	ILT Class	11/5/2012
FRM470	FRM470 - ES Annual In	ILT Course	11/5/2012
ADMFGD26	FGD Conduct of Opera	ILT Course	11/6/2012
ADMFGD26 0020	FGD Conduct of Opera	ILT Class	11/6/2012
ENV0004G	Hazwoper Level I - Aw	ILT Course	11/22/2012
SEC0003	Impact NERC Stds. Pw	eLearning	11/22/2012
SEC0004	Ops Require for NERC	eLearning	11/22/2012
SF2123	Safe Driving	ILT Course	11/22/2012
ENC0015G	STORMWATER POLLU	ILT Course	11/22/2012
NERC2012	NERC Awareness Train	eLearning	12/9/2012
OPI0005F	OPI0005F - Power Gen	ILT Course	2/5/2013
OPI0005F 0015	Pwr Gen Station Mgr	ILT Class	2/5/2013
SF2108	ACCESS TO MEDICAL R	ILT Course	3/2/2013
SF478	FIRE EXTINGUISHERS	ILT Course	3/2/2013
SF800	Hearing Conservation	ILT Course	3/2/2013
TR0113	Hearing Conservation/	ILT Course	3/2/2013
HS0418	DO NOT USE THIS COU	eLearning	3/12/2013
HS0454	DO NOT USE THIS COU	ILT Course	3/12/2013

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SF478P	FIRE EXTINGUISHERS F ILT Course	3/12/2013
PMC-001 HS0418	DO NOT USE THIS COU eLearning	3/13/2013
GN6CEDF	Env. Awareness -Level eLearning	3/13/2013
GN6C108G-N 00000-N	GN6C108G-N 00000-N ILT Class	3/14/2013
GN6C108G-N	GN6C108G-N Environ. ILT Course	3/14/2013
CEMS07	CEMS07 - CT CEMS Op ILT Course	4/8/2013
FME100F	FGD Foreign Material I eLearning	5/24/2013
MEI0024G	Lube Oil Awareness eLearning	5/24/2013
EHSENV01	SPCC Spill Prevention/ eLearning	5/24/2013
EV617IG-N	EV617IG-N SPCC SPILL eLearning	5/25/2013
SFI0200G-N	SFI0200G-N FALL PRO1 eLearning	5/25/2013
HS0720	EHST - Fall Protection I ILT Course	5/25/2013
HS0720 EHST1700030	EHST - Fall Protection I ILT Class	5/25/2013
HS0003	EHST - Fall Protection I eLearning	5/25/2013
DE-120764	EHST-Fall Protection T ILT Course	5/25/2013
CIP004R2_P	NERC Cyber Sec-Critica Material	7/28/2013
PGL677	PGL677 Backing Policy ILT Course	8/9/2013
EC10613	CoBE Refresher Trainir eLearning	8/19/2013
SEC0018	PGF Gene Op for Main eLearning	8/25/2013
CIPOP4PV	POG Gen Aware Ops N eLearning	8/25/2013
SEC0001	For NERC Admins Only ILT Course	7/17/2017
DE-126351	DE-126351 - RRE Arc F eLearning	7/18/2017
FHO111	FHO111 - Fossil Hydro ILT Course	7/18/2017
FHO111 000172	FHO111 - Fossil Hydro ILT Class	7/18/2017
IT800	Duke Energy's Top 10 : eLearning	7/19/2017
HR0113	Maintaining a Harassn eLearning	7/19/2017
EN1000	EHST - Environmental eLearning	7/19/2017
LDIT111	Security Awareness fo eLearning	7/19/2017
FHO942	FHO942 - Control of R: eLearning	7/19/2017
HS0089	EHST - Respirable Crys eLearning	7/20/2017
HS0735	EHST - Radio Frequenc eLearning	7/20/2017
EC10617	Code of Business Ethic eLearning	7/20/2017
LD325	Sustainability 101 eLearning	7/25/2017
EHS1000	EHST - EHS Foundatio eLearning	7/25/2017
EN0002	EHST - Hazard Commu eLearning	7/25/2017
EN0003	Hazard Communicatio eLearning	7/25/2017
TransEngComplFLReg	Regulatory Complianc Objective	7/25/2017
ISW709	Information Security A eLearning	7/25/2017
LD100	MyTraining - Learner C eLearning	7/25/2017
PGL7700	PGL7700 - Initial Oper: ILT Course	7/27/2017
PGL7700 000003	PGL7700 - Initial Oper: ILT Class	7/27/2017
ADMF26PV	FGD Conduct Of Oper: eLearning	7/27/2017
XEHS02	XEHST - Environmenta ILT Course	7/31/2017
XEHS02 000016	XEHST - Environmenta ILT Class	7/31/2017
EC10317	Code of Business Ethic eLearning	8/2/2017

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DE-121834	EHST - Thermal Stress eLearning	8/24/2017
HS0327	EHST - Cold Stress - HS eLearning	8/24/2017
HS0749	EHST - Personal Protec eLearning	8/24/2017
EN0015	EHST - Chemical Inven eLearning	8/24/2017
HS1011	Ergonomic Safety Ovei eLearning	8/24/2017
HS0136	EHST - Respirator Usag eLearning	8/24/2017
HS0247	Asbestos, Man-made \ eLearning	8/24/2017
DE-124444	EHST - Heat Stress Gap eLearning	8/25/2017
HS0328	EHST - Heat Stress - HS eLearning	8/25/2017
EN0068	Migratory Bird Treaty . eLearning	8/25/2017
HS0739	Hazard Awareness: Sli eLearning	8/25/2017
EN0016	EHST - Chemical Inspe eLearning	8/25/2017
EN0126	EHST - Universal Wast eLearning	8/25/2017
EN0403	EHST - Corporate Cher eLearning	8/25/2017
COT148C	NO NOT USE THIS COL eLearning	8/25/2017
EN0136	EHST - Understanding eLearning	8/25/2017
PGL690	PGL690 - LOTO Proced ILT Course	10/3/2017
PGL690 000401	PGL690 - LOTO Proced ILT Class	10/3/2017
PGL692	PGL692 - FHO Annual I eLearning	10/3/2017
PGLZEV	PGLZEV - Electrical ZEV ILT Course	10/4/2017
PGLZEV 000116	PGLZEV - Electrical ZEV ILT Class	10/4/2017
PGL691	PGL691 - LOTO Desk Ti ILT Course	10/4/2017
PGL691 000080	PGL691 - LOTO Desk Ti ILT Class	10/4/2017
EC22017	NERC Awareness Train eLearning	10/25/2017
IT816	Security Awareness fo eLearning	10/25/2017
HS0235E	EHST - Asbestos Class I eLearning	11/12/2017
HS0235	EHST - CLASS IV ASBES ILT Course	11/12/2017
HS0246	EHST - Class IV Asbest eLearning	11/12/2017
FHOEIC201FL	FHOEIC201FL - RRE-FL ILT Course	11/28/2017
FHOEIC201FL 170001	FHOEIC201FL - RRE-FL ILT Class	11/28/2017
FHO722	FHO722 - Initial for No ILT Course	1/16/2018
FHO722 000040	FHO722 - Initial for No ILT Class	1/16/2018
FHOOSS211LAB	FHOOSS211LAB - Oper ILT Course	2/5/2018
FHOOSS211LAB 180000	FHOOSS211LAB - Oper ILT Class	2/5/2018
FHO2334	FHO2334 - Condensate ILT Course	2/7/2018
FHO2334 180000	FHO2334 - Condensate ILT Class	2/7/2018
FHONGP100	FHONGP100 - Hydroge ILT Course	2/7/2018
FHONGP100 180000	FHONGP100 - Hydroge ILT Class	2/7/2018
FHOGHP100	FHOGHP100 - Natural ILT Course	2/7/2018
FHOGHP100 180000	FHOGHP100 - Natural ILT Class	2/7/2018
PGC023	PGC023 - Continuous E ILT Course	2/7/2018
PGC023 180001	PGC023 - Continuous E ILT Class	2/7/2018
FHO003	FHO003 - Environmenl ILT Course	2/14/2018
FHO003 180001	FHO003 - Environmenl ILT Class	2/14/2018
EHSSWTF2	System S&T - Plant Op eLearning	3/20/2018

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DEIA001	Duke Energy In Action eLearning	5/7/2018
FHOFL252	FHOFL252 Operator MILT Course	5/31/2018
FHOFL252 180006	FHOFL252 Operator MILT Class	5/31/2018
FHO225	FHO225 - LOTO Procec eLearning	7/4/2018
HS0112	EHST - EHS-Basic Respi eLearning	8/27/2018
HS0282	EHST - Electrical Safety eLearning	8/27/2018
TransEngComplFLDep	Department Directives Objective	8/27/2018
ENC005	EHST - Spill Prevention eLearning	8/27/2018
HR0411	Social Media Practices eLearning	8/27/2018
EC10618	Code of Business Ethic eLearning	8/27/2018
HS0701	Fire Extinguisher Annu ILT Course	8/29/2018
HS0701 000529	Fire Extinguisher Annu ILT Class	8/29/2018
HS0081	EHST - Emergency Plar ILT Course	8/30/2018
HS0081 000006	EHST - Emergency Plar ILT Class	8/30/2018
HS0081E	EHST - Emergency Plar eLearning	8/30/2018
FHO111A	Arc Flash Safety 2018 I ILT Course	9/26/2018
FHO111A 000025	Arc Flash Safety 2018 I ILT Class	9/26/2018
HS0142	EHST - Supported and eLearning	10/22/2018
FHOWRKM001	FHOWRKM001 - FHO \ ILT Course	11/27/2018
FHOWRKM001 000045	FHOWRKM001 - FHO \ ILT Class	11/27/2018
HS1010	EHST - Workplace Safe eLearning	1/25/2019
HS1003	Office Safety - EHST eLearning	1/25/2019
HS1002	Workplace Ergonomic: eLearning	1/25/2019
IT709	Cybersecurity and You eLearning	2/18/2019
MEI0023G	MEI0023G MOV Oper: ILT Course	3/2/2019
MEI0023R	MOV Actuators Retrng eLearning	3/2/2019
CHA07G	Basic Fossil Plant Chen eLearning	3/2/2019
EHSSWT1R	ED Switching & Taggin eLearning	5/7/2019
EHSSWTR2	System S&T Retr n for l eLearning	5/7/2019
MGS196:DE-102880	MGS196 - RRE Standar ILT Class	6/23/2019
FHO1027	FHO1027 - RRE LOTO F ILT Course	6/27/2019
FHO1027 000010	FHO1027 - RRE LOTO F ILT Class	6/27/2019
DE-91611	FHO1027CBT LOTO Prc eLearning	6/27/2019
FHONERCCIP003A	FHONERCCIP003A - Clf eLearning	9/12/2019
TTC2123-N	TTC2123-N Bloodborn: ILT Course	9/28/2019
HS0545	EHST - Bloodborne Pat eLearning	9/28/2019
FHONERCPRC004T1	FHONERCPRC004T1 - F ILT Course	10/31/2019
FHONERCPRC004T1:DE-1	FHONERCPRC004T1 - F ILT Class	10/31/2019
DE-113400	DE-113400 Harassmen eLearning	11/2/2019
LDHFWEO1	Training for a Harassm eLearning	11/2/2019
EN0065E	EHST - Approaching & eLearning	12/30/2019
DE-101485	EC - 2019 Code of Busi eLearning	1/16/2020
MGS196:DE-107671	MGS196 - RRE Standar ILT Class	1/23/2020
DE-108639	DE-108639 - Crystal Ri ILT Course	2/1/2020
DE-108639:DE-109759	DE-108639 - Crystal Ri ILT Class	2/1/2020

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PGO108	PGO108 - Combined C ILT Course	2/19/2020
PGO108 190001	PGO108 - Combined C ILT Class	2/19/2020
FHO693PLTW	FHO693PLTW - NERC C eLearning	5/3/2020
DE-109696	DE-109696_COVID-19 eLearning	6/18/2020
PGL362	PGL362 - Generator O eLearning	8/8/2020
DE-112729	DE-112729 - RRE LOTO ILT Course	8/10/2020
DE-112729:DE-113625	DE-112729 - RRE LOTO ILT Class	8/10/2020
DE-112728	DE-112728 - RRE LOTO ILT Course	8/10/2020
DE-112728:DE-113597	DE-112728 - RRE LOTO ILT Class	8/10/2020
DE-109177	Cybersecurity Awaren eLearning	8/12/2020
DE-113441	EC - 2020 Code of Busi eLearning	9/15/2020
FHO1031	FHO1031 -Regulated & eLearning	9/15/2020
DE-112202	DE-112202 - LOTO Pro eLearning	10/2/2020
DE-103722	EHST - Introduction to eLearning	12/9/2020
HS2014	EHST - Duke Energy Sa eLearning	12/23/2020
HS0221	EHST - Beryllium Awar eLearning	12/23/2020
HS0800	EHST - Fire Extinguisher eLearning	12/23/2020
HS0802	EHST -Fire Extinguisher ILT Course	12/23/2020
HS0702	Fire Extinguisher Annu eLearning	12/23/2020
PGL800	PGL800 - FHO Annual l eLearning	1/1/2021
PGL427	PGL427 - Generation P eLearning	2/23/2021
HS9054	EHST - Emergency Sho eLearning	2/24/2021
EN0213	EHST - DOT General A eLearning	2/24/2021
PGL426	PGL426 - Introduction eLearning	2/24/2021
OPEX0001	OPEX_Pre-Job Brief Tr eLearning	3/8/2021
HS0024	EHST - Hearing Conser eLearning	3/8/2021
HS0088	EHST - Lead in Constru eLearning	3/20/2021
HS0729	EHST - Portable Grinde eLearning	3/20/2021
FHO1030	FHO1030 - Regulated l eLearning	3/30/2021
HS0220	EHST - Inorganic Arsen eLearning	3/30/2021
HS0645	EHST - Waterborne Pa eLearning	3/30/2021
HS9070	EHST - Hexavalent Chr eLearning	3/30/2021
DE-118825	DE-118825 - RRE High- eLearning	5/9/2021
DE-119042	DE-119042 - RRE High- eLearning	5/9/2021
DE-118717	DE-118717 - RRE High- eLearning	5/9/2021
DE-129402	DE-129402 - RRE LOTO eLearning	5/15/2021
DE-118828	DE-118828 - RRE High- eLearning	5/28/2021
DE-119124	DE-119124 ? RRE High- eLearning	5/28/2021
DE-119127	DE-119127 - RRE High- eLearning	5/28/2021
DE-118745	DE-118745 ? RRE High- eLearning	5/29/2021
DE-129773	DE-129773 - Conveyor Material	5/29/2021
EN0121	EHST - Hazardous Was eLearning	6/4/2021
FHO1033	FHO1033 - Regulated l eLearning	6/4/2021
PGL905CBT	PGL905CBT - Radiator eLearning	6/4/2021
DE-129528	Cybersecurity Awaren eLearning	6/5/2021

FHO1032	FHO1032 - Regulated eLearning	6/11/2021
EN0071	EHST - Migratory Bird eLearning	6/11/2021
MGS196	MGS196 - RRE Standar ILT Course	6/17/2021
MGS196:DE-132109	MGS196 - RRE Standar ILT Class	6/17/2021
PGL790	PGL790 - Security Incic eLearning	6/22/2021
ENW009	EHST - Storm Water Pc eLearning	8/19/2021
FHO970e	FHO970e - Hydrogen S eLearning	8/28/2021
SF149 0256	Am Heart/ASHI Adult (ILT Class	NOT COMPLETE - RLG
SF149 0284	Am Heart/ASHI Adult (ILT Class	NOT COMPLETE - RLG
SF149 0519	Am Heart/ASHI Adult (ILT Class	NOT COMPLETE - RLG
EL0018P 0042	Arc Flash Practical ILT Class	NOT COMPLETE - RLG
TR0117	Basic Electricity eLearning	NOT COMPLETE - RLG
DIVEW01 0227	Business Case for Dive ILT Class	NOT COMPLETE - RLG
DE-105900:DE-129429	DE-105900 - Human Pe ILT Class	NOT COMPLETE - RLG
FHO2111	FHO2111 - RRE Contra eLearning	NOT COMPLETE - RLG
GNI0007N-N	GNI0007N-N AERIAL Li eLearning	NOT COMPLETE - RLG
HR0003F	HR0003F - Human Errc ILT Course	NOT COMPLETE - RLG
HR0003F 0192	Human Error Reduct-Ir ILT Class	NOT COMPLETE - RLG
HR0003F 0246	Human Error Reduct-Ir ILT Class	NOT COMPLETE - RLG
ITF0084G-N 00000-N	ITF0084G-N 00000-N P ILT Class	NOT COMPLETE - RLG
ITF0084G-N	ITF0084G-N PassPort F ILT Course	NOT COMPLETE - RLG
ME206G-N 0298-N	ME206G-N 0298-N Init ILT Class	NOT COMPLETE - RLG
PGL955	PGL955 - Configuratio eLearning	NOT COMPLETE - RLG
ST0006-N 00000-N	ST0006-N 00000-N Pla ILT Class	NOT COMPLETE - RLG
ST1263-N 00000-N	ST1263-N 00000-N Cr3 ILT Class	NOT COMPLETE - RLG
ST1263-N 0037-N	ST1263-N 0037-N Cr3 I ILT Class	NOT COMPLETE - RLG
TTC1417-N	TTC1417-N FME Worki ILT Course	NOT COMPLETE - RLG
MEI0022G 0008	Valves Operation Trair ILT Class	NOT COMPLETE - RLG
GNF0003G	Work Mgmt for Craft ILT Course	NOT COMPLETE - RLG
GNF0003G 0025	Work Mgmt for Craft ILT Class	NOT COMPLETE - RLG

Instruction Book

**M-0359 Syncrocloser®
Check Plus**

BECKWITH  **CO. INC.
ELECTRIC**

Syncrocloser® Check Plus M-0359



- **Enhances system stability when applied to transmission and primary distribution reclosing schemes**
- **Detects a static phase angle across an open breaker in 0.5 second to assure a fast permissive for reclosure**
- **Simultaneously measures voltage magnitudes to ensure that they are within upper, lower and difference limits**
- **Includes dead line/dead bus closing features**
- **Remote command widens the phase angle setpoint to respond to system emergencies or to narrow the setpoint when the two systems are isolated to close the breaker very close to 0°**
- **Transducer analog outputs are SCADA compatible**

INPUTS

1. Power is derived from either the Line or Bus input, whichever is greater. Below 65 V, the low voltage detection circuitry will shut down the M-0359.
2. Line voltage, nominal 120 V ac, 145 V ac maximum continuous. Will withstand 240 V ac for 1 sec.
3. Bus voltage, nominal 120 V ac, 145 V ac maximum continuous. Will withstand 240 V ac for 1 sec.

■ **NOTE:** Line and Bus voltage inputs are transformer-isolated, allowing complete freedom in applications.

4. Select Dead Bus Close (by closing contact)*.
5. Select Dead Line Close (by closing contact)*.

*■ **NOTE:** One input must be greater than 100 V ac to ensure output relay closure.

6. Shift **PHASE ANGLE LIMIT** setpoint. An external contact closure will reduce the setpoint by a specified ratio. This can also be used as a widening function by operating with the external terminals normally closed.
7. Enable Sync-Check.

BURDEN

Whichever input voltage is high, 11 VA; other input, 1 VA.

CONTROLS

UPPER VOLTAGE LIMIT: 110 to 140 V ac either input, dial calibration accuracy $\pm 2\%$ of full scale.

LOWER VOLTAGE LIMIT: 90 to 120 V ac either input, dial calibration accuracy $\pm 2\%$ of full scale.

DELTA V LIMIT: 1 to 5 V, dial calibration accuracy $\pm 5\%$ of full scale. Other ranges available.

DEAD LINE LIMIT: 10 to 60 V, dial calibration accuracy $\pm 7\%$ of full scale.

DEAD BUS LIMIT: 10 to 60 V, dial calibration accuracy $\pm 7\%$ of full scale.

PHASE ANGLE LIMIT: 0 to $\pm 30^\circ$, dial calibration accuracy $\pm 5\%$ of full scale. Other ranges available.

DELTA F LIMIT: 0.01 to 0.5 Hz, dial calibration accuracy $\pm 5\%$ of full scale.

■ **NOTE:** Controls are independent of each other and do not require additional instrumentation for field setting.

LED INDICATORS

All LEDs are lit when conditions are met to close the breaker.

BUS UPPER VOLTAGE LIMIT OK

LINE UPPER VOLTAGE LIMIT OK

BUS LOWER VOLTAGE LIMIT OK

LINE LOWER VOLTAGE LIMIT OK

DELTA V OK

LINE HOT

BUS HOT

ANGLE OK

DELTA F OK

BREAKER CLOSE RELAY

Dry output contacts rated to make and carry 20 A at 250 V dc, and interrupt 0.9 A at 120 V dc or 0.4 A at up to 250 V dc inductive load. Open contacts will withstand 1500 V ac for 1 min. Contacts to ground will withstand 1500 V ac for 1 min.

RESPONSE TIME

When the Line and Bus inputs are first applied to the unit, the voltage magnitude circuits require approximately 0.5 sec. to sense the correct voltage. The unit will simultaneously measure phase angle and close the breaker with proper phase angle after this initial delay. In closing on dead line or dead bus, the phase condition is ignored so that the unit will close upon a voltage below the set threshold in approximately 0.5 sec.

STATUS RELAY CONTACTS

Voltage Status Relay: Closed when Voltage conditions are within limits.

Phase Angle Status Relay: Closed when Phase Angle is within limits.

Delta Frequency Status Relay: Form C contact provided.

These are light duty contacts intended primarily for status interrogation by supervisory. They can be used to light local lights with the following restrictions:

1/2 A at 125 V dc resistive; 1 A at 120 V ac, 250 V dc across open contacts

ANALOG OUTPUTS

Various dc analog outputs are provided for Bus Voltage, Line Voltage, Delta V, Phase Angle, and Delta F. These analog outputs can interface with most SCADA systems.

RELIABILITY

The M-0359 Syncrocloser® Check Plus relay is assembled on three glass-epoxy printed circuit boards. All semiconductor components are hermetically sealed, and of the highest and most reliable quality available. Highly stable, instrument-grade capacitors and resistors are used in critical measurement circuits to minimize the possibility of error.

TRANSIENT PROTECTION

Input and output circuits are protected against system transients. The M-0359 will pass all requirements of ANSI/IEEE C37.90.1-1989, which defines oscillatory and fast transient surge withstand capability. All inputs and outputs will withstand 1500 V ac to chassis or instrument ground for one minute. Voltage inputs are electrically isolated from each other, from other circuits, and from ground.

ENVIRONMENTAL

Temperature Range: Units will operate properly over a temperature range of -40° to $+80^{\circ}\text{C}$.

Humidity: Stated accuracies are maintained at up to 95% relative humidity (non-condensing).

Fungus Resistance: A conformal printed circuit board coating inhibits fungus growth.

PHYSICAL

Size: 19" wide x 3-1/2" high x 13" deep (48.3 cm x 8.9 cm x 33.0 cm). Requires two rack units space in a standard 19" rack. May also be panel mounted horizontally or vertically.

Approximate Weight: 15 lb (6.8 kg).

Approximate Shipping Weight: 20 lb (9.1 kg).

SYNCROCLOSER® COVER KIT M-0217

The M-0217 may be ordered that includes a transparent cover and mounting bracket to cover the controls and prevent accidental resetting.

PATENT

The M-0359 Syncrocloser Check Plus relay is covered by U.S. Patent 4,218,625.

WARRANTY

The M-0359 Syncrocloser Check Plus relay is covered by a five year warranty from date of shipment.

Specification is subject to change without notice.

BECKWITH ELECTRIC CO., INC.

6190 - 118th Avenue North • Largo, Florida 33773-3724 U.S.A.

PHONE (727) 544-2326 • FAX (727) 546-0121

marketing@beckwithelectric.com

www.beckwithelectric.com

ISO 9001:2008

WARNING

DANGEROUS VOLTAGES, capable of causing death or serious injury, are present on the external terminals and inside the equipment. Use extreme caution and follow all safety rules when handling, testing or adjusting the equipment. However, these internal voltage levels are no greater than the voltages applied to the external terminals.

DANGER! HIGH VOLTAGE



- This sign warns that the area is connected to a dangerous high voltage, and you must never touch it.

PERSONNEL SAFETY PRECAUTIONS

The following general rules and other specific warnings throughout the manual must be followed during application, test or repair of this equipment. Failure to do so will violate standards for safety in the design, manufacture, and intended use of the product. Qualified personnel should be the only ones who operate and maintain this equipment. Beckwith Electric Co., Inc. assumes no liability for the customer's failure to comply with these requirements.



- This sign means that you should refer to the corresponding section of the operation manual for important information before proceeding.



Always Ground the Equipment

To avoid possible shock hazard, the chassis must be connected to an electrical ground. When servicing equipment in a test area, the Protective Earth Terminal must be attached to a separate ground securely by use of a tool, since it is not grounded by external connectors.

Do NOT operate in an explosive environment

Do not operate this equipment in the presence of flammable or explosive gases or fumes. To do so would risk a possible fire or explosion.

Keep away from live circuits

Operating personnel must not remove the cover or expose the printed circuit board while power is applied. In no case may components be replaced with power applied. In some instances, dangerous voltages may exist even when power is disconnected. To avoid electrical shock, always disconnect power and discharge circuits before working on the unit.

Exercise care during installation, operation, & maintenance procedures

The equipment described in this manual contains voltages high enough to cause serious injury or death. Only qualified personnel should install, operate, test, and maintain this equipment. Be sure that all personnel safety procedures are carefully followed. Exercise due care when operating or servicing alone.

Do not modify equipment

Do not perform any unauthorized modifications on this instrument. Return of the unit to a Beckwith Electric repair facility is preferred. If authorized modifications are to be attempted, be sure to follow replacement procedures carefully to assure that safety features are maintained.

PRODUCT CAUTIONS

Before attempting any test, calibration, or maintenance procedure, personnel must be completely familiar with the particular circuitry of this unit, and have an adequate understanding of field effect devices. If a component is found to be defective, always follow replacement procedures carefully to that assure safety features are maintained. Always replace components with those of equal or better quality as shown in the Parts List of the Instruction Book.

Avoid static charge

This unit contains MOS circuitry, which can be damaged by improper test or rework procedures. Care should be taken to avoid static charge on work surfaces and service personnel.

Use caution when measuring resistances

Any attempt to measure resistances between points on the printed circuit board, unless otherwise noted in the Instruction Book, is likely to cause damage to the unit.

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INTRODUCTION

Please refer to the M-0359 Application Guide in conjunction with this Instruction Book since information contained in one is not usually repeated in the other.

The Beckwith Electric M-0359 Syncrocloser® Check Plus relay uses advanced state-of-the-art semiconductors and circuits to achieve an overall stability and resolution unattainable with current electromechanical sync-check relays. Modern hybrid and monolithic semiconductors using ion implantation and laser trimming are incorporated throughout the Syncrocloser Line to gain temperature stability without critical compensation or trimming.

THEORY OF OPERATION

PHASE ANGLE BOARD AND VOLTAGE BOARD

Refer to Figure 1 Block Diagram. Operating dc voltages are supplied by the power supply section. Input power is driven from either line or bus depending on which is greater in voltage magnitude. Each input (line, bus) is passed through a transformer and scaled down from 120 V ac to 6 V ac. The scaled down voltage is converted to a dc voltage by the ac to dc converter. This converter is an active full-wave rectifier and filter, which eliminates the usual highly temperature-dependent diode drop of conventional full-wave rectifiers. Full-wave rectification was chosen over half-wave rectification because the filter time response is much faster for a given ripple voltage. This is due to the fact that full-wave rectification results in a voltage containing no fundamental frequency components, only harmonics.

Upper and lower voltage comparators compare the output of each ac to dc converter to a portion of a highly stable hybrid 10 V reference. LEDs located on the front panel indicate the condition of each input (line, bus) with reference to upper and lower voltage limits. The dead line/dead bus comparators determine whether either input (line, bus) is below the threshold of the comparator setting. The comparison voltage is the stable 10 V reference, and LEDs indicate each input status.

An absolute value difference amplifier precisely evaluates the difference voltage (Delta V) between the line and bus input, and a comparator compares Delta V to a portion of the stable reference voltage. Again, a front panel LED indicates the status of Delta V. Two zero-crossing detectors generate rectangular waveforms at the zero-crossing of each input. The exclusive OR-gate provides a pulse width proportional to the phase angle between each input. A three-pole active filter provides the required averaging without the excessive time delay of conventional RC filters.

Phase angle voltage varies from 0 to 5 V for a 0° to 180° phase change. A scaling amplifier precisely increases the phase angle voltage (Φ) to provide higher phase angle resolution. The phase angle comparator compares Φ to preset limits. If Φ is within limits, a "close" condition is sent to the logic section. If all voltages and the difference frequency, Delta F, at the inputs are within preset limits, then the output relay is picked up until the phase angle, Delta F or input voltages drop outside the limits.

Dead Line or Dead Bus Closing may be programmed externally, and are functions of the dead line/dead bus logic. The output relay will pick up whenever a dead condition is sensed at the required input, regardless of phase angle, upper and lower voltage limits, Delta V or Delta F. The program may be selected as dead line, dead bus, dead line or dead bus, but not dead line and dead bus.

DELTA F BOARD

The phase angle voltage from the Phase Board is input to a second order filter. The filter provides additional averaging to the phase angle voltage. The slope of the phase angle voltage, $d\Phi/dt$, is directly proportional to the difference frequency, Delta F. This derivative is bipolar, depending upon the direction of phase change. By taking the absolute value of $d\Phi/dt$, continuous monitoring of Delta F is achieved without the usual "deadband." Absolute value and time derivative $d\Phi/dt$ are functions of the absolute value amplifier (U1B) and the precision derivative amplifier (U1A). This is followed by a comparator (U2A) which drives a front panel LED indicator and the Delta F status relay.

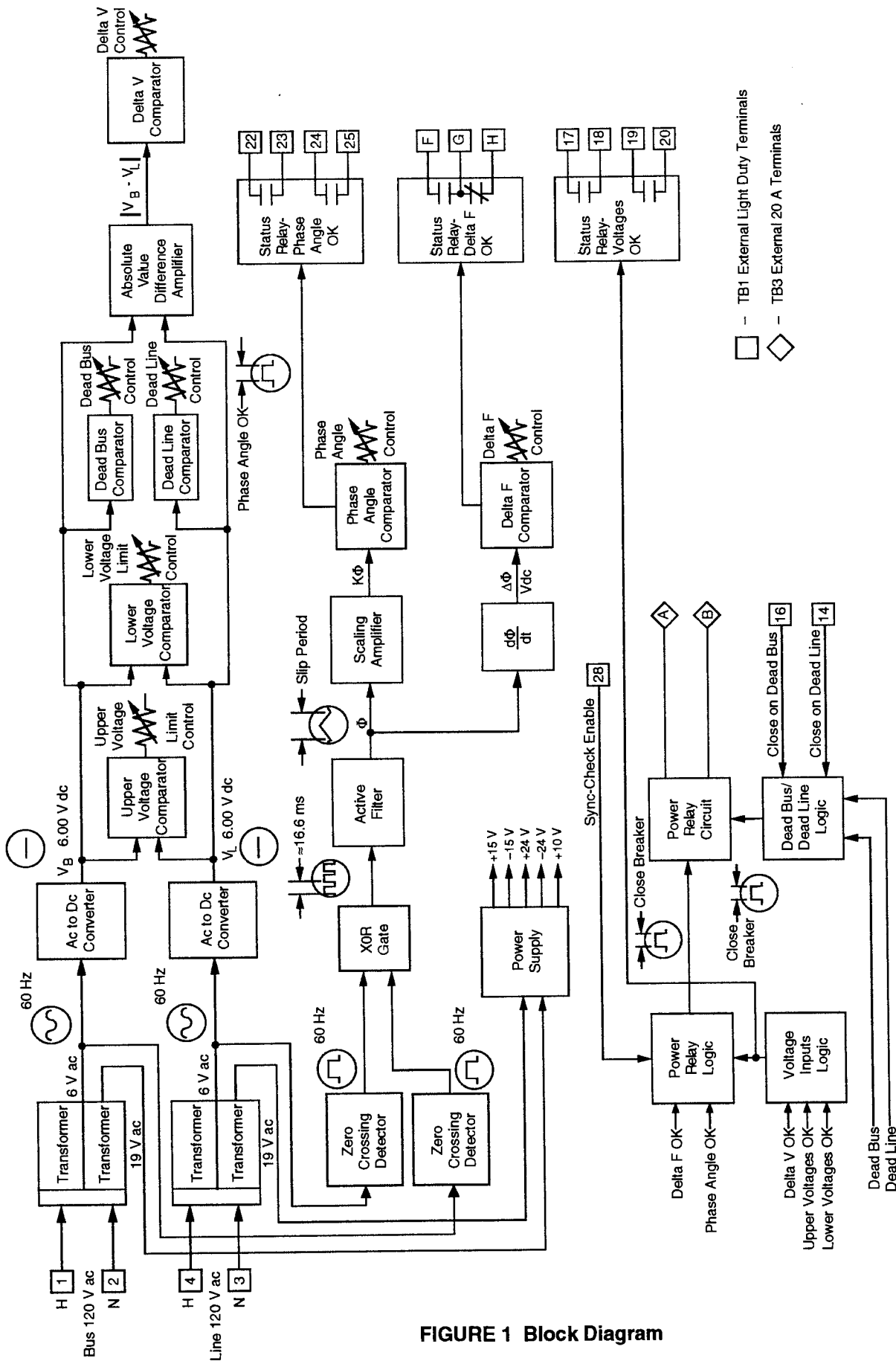


FIGURE 1 Block Diagram

TEST PROCEDURES

TEST SOURCES

Two highly stable test sources must be used to test the M-0359. The power system is suitable as one input for a "general" test, but is not sufficiently stable in phase or frequency to determine the limits of the accuracy of the M-0359.

To properly test the M-0359, each input must have a short-term frequency stability of ± 0.001 Hz and phase jitter at no more than 0.1° peak to peak.

EQUIPMENT REQUIRED

1. Two distortion free 60 Hz variable sources, as follows:
 - a. A variable frequency, variable phase angle source capable of providing 120 V ac. Maximum phase jitter of 0.1° .
 - b. A fixed frequency source capable of providing 120 V ac. Maximum phase jitter of 0.1° .
2. Two digital multimeters with ac and dc accuracy of 0.2% of full-scale ± 1 least significant digit; Hewlett-Packard 3465A or equivalent.
3. A solder sucking syringe or solder wick.
4. A soldering iron - Weller Controlled Output Soldering Station, model MTCPL, 60 W, 120 V, 50/60 Hz or equivalent.
5. A stopwatch or any accurate timing device.

COMPONENT REPLACEMENT PROCEDURE

1. To gain access to the circuit board, remove the top and bottom covers of the unit. Components can now be easily tested or changed. Analysis of the circuit will then often lead to the cause of the failure and components to be replaced.
2. If a component needs to be changed, carefully scrape away the coating surrounding the component using a small, sharp knife, being careful not to damage the printed circuit path.
3. Clip out the old component and discard.
4. Remove the clipped wires using the solder wick or syringe. Be sure to leave the holes clear to facilitate insertion of the new component.

▲ CAUTION: Do not attempt to melt the solder and push the new component through the hole as the leads are likely to catch the edge of the foil and lift it off the board.

5. When replacing integrated circuits, be sure to insert the unit into the transipad so that the tab fits into the slot. Once this is done, there is only one way to insert the combination into the printed circuit board.

TEST PROCEDURE

Refer to Figure 2 External Connections, Figure 5 Phase Board Component Location, Figure 6 Voltage Board Component Location, and Figure 7 Delta F Board Component Location.

UPPER VOLTAGE LIMIT

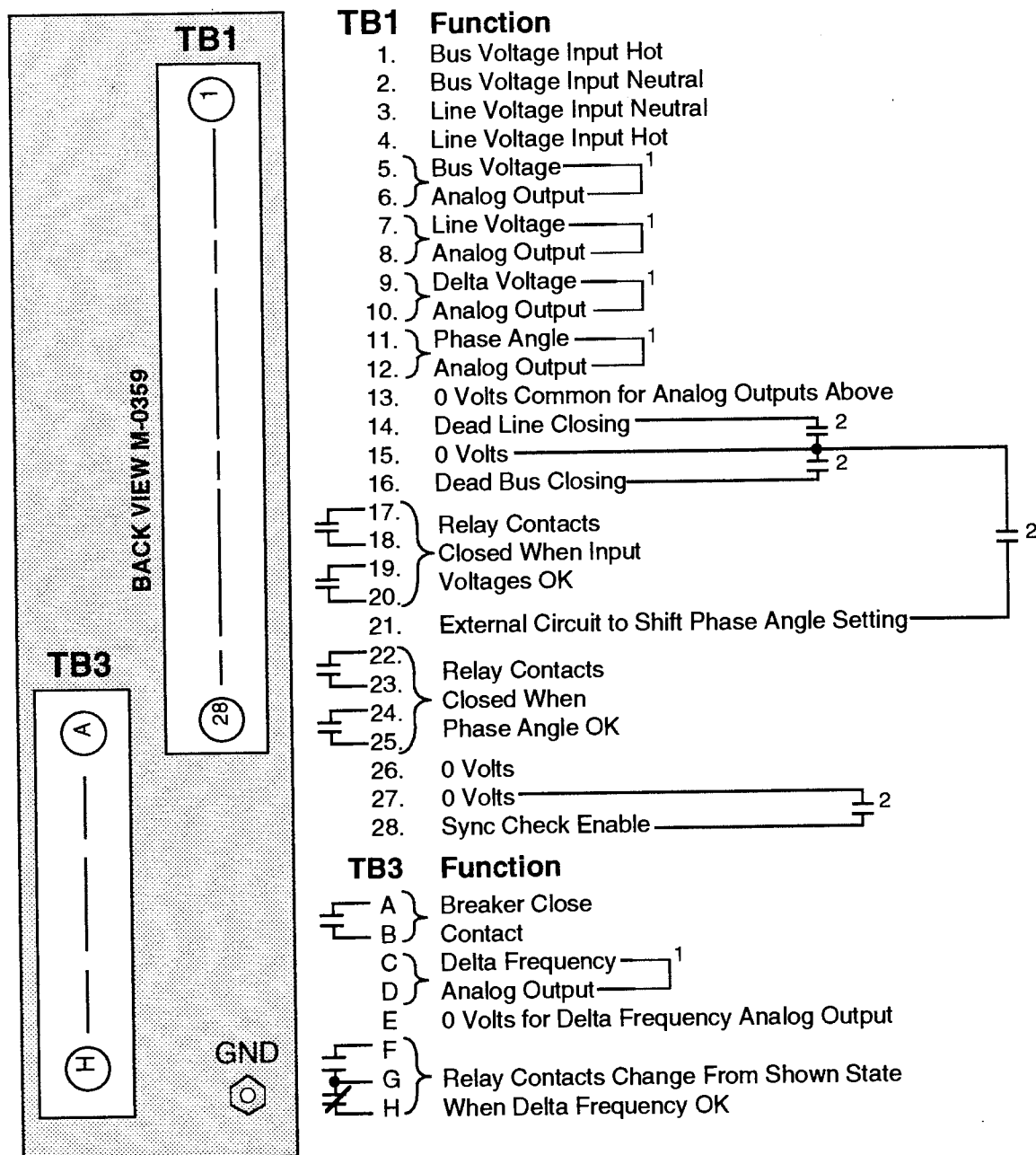
1. Set the **UPPER VOLTAGE LIMIT** control at 125 V.
2. Supply 120 V ac, 60 Hz to the Bus input TB1-1 and TB1-2, noting that TB1-1 is the HOT terminal.
3. Supply 120 V ac, 60 Hz to the Line input TB1-3 and TB1-4, noting that TB1-4 is the HOT terminal.
4. Slowly increase the Bus input until the **UPPER VOLTAGE LIMIT BUS OK** LED turns off. The LED should turn off at $125\text{ V} \pm 2.8\text{ V}$.
5. Decrease the Bus input to 120 V.
6. Slowly increase the Line input until the **UPPER VOLTAGE LIMIT LINE OK** LED turns off. The LED should turn off at $125\text{ V} \pm 2.8\text{ V}$.
7. Decrease the Line input to 120 V.

LOWER VOLTAGE LIMIT

1. Set the **LOWER VOLTAGE LIMIT** control at 105 V.
2. Supply 120 V ac, 60 Hz to the Bus input TB1-1 and TB1-2, noting that TB1-1 is the HOT terminal.
3. Supply 120 V ac, 60 Hz to the Line input TB1-3 and TB1-4, noting that TB1-4 is the HOT terminal.
4. Slowly decrease the Bus input until the **LOWER VOLTAGE LIMIT BUS OK** LED turns off. The LED should turn off at $105 \pm 2.4\text{ V}$.
5. Increase the Bus input to 120 V.
6. Slowly decrease the Line input until the **LOWER VOLTAGE LIMIT LINE OK** LED turns off. The LED should turn off at $105 \pm 2.4\text{ V}$.
7. Increase the Line input to 120 V.

DELTA V LIMIT

1. Set the **DELTA V LIMIT** control at midscale.
2. Supply 110 V ac, 60 Hz to the Bus input TB1-1 and TB1-2, noting that TB1-1 is the HOT terminal.



■ **NOTES:**

1. External connections are shown for voltage output and current output in Figures 3 and 4 of the Application Guide.
2. Close the external circuit to enable the function. These inputs should **not** be permanently jumpered, since an inadvertent close command can take place if a voltage transformer or it's associated circuit fails open.
3. Close the external circuit to enable the function. If a function is required at all times, permanent enable jumpers may be added.

FIGURE 2 External Connections

3. Supply 110 V ac, 60 Hz to the Line input TB1-3 and TB1-4, noting that TB1-4 is the HOT terminal.
4. Slowly increase the line input voltage until the **DELTA V LIMIT OK** LED turns off. The LED should turn off at 1/2 the scale setting $\pm 5\%$ of full scale.

Example: With a **DELTA V LIMIT** full scale range of 10 V, the midscale value would be 5 V. Therefore, the LED should turn off at 5 V ± 0.5 V (voltage difference).

DEAD LINE LIMIT

1. Place a jumper between TB1-14 and TB1-15.
2. Adjust the **DEAD LINE LIMIT** control to 40 V.
3. Slowly reduce the Line voltage. The output Breaker Close Relay should pick up as the Line voltage goes below 40 V. The **DEAD LINE LIMIT OK** LED should extinguish at the same time.
4. Return the Line voltage to 120 V ac.

DEAD BUS LIMIT

1. Place a jumper between TB1-15 and TB1-16.
2. Adjust the **DEAD BUS LIMIT** control to 40 V.
3. Slowly reduce the Bus voltage. The output Breaker Close Relay should pick up as the Bus voltage goes below 40 V. The **DEAD BUS LIMIT OK** LED should extinguish at the same time.
4. Return the Bus voltage to 120 V ac.

PHASE ANGLE LIMIT

1. Adjust the **PHASE ANGLE LIMIT** control to midscale.
2. Slowly adjust the phase difference between the Line and Bus to midscale (15°, 30° or 45° depending on the scale selected). The **PHASE ANGLE LIMIT OK** LED will extinguish as the midscale angle is passed.

DELTA F LIMIT

1. Adjust the **DELTA F LIMIT** control to 0.25 Hz.
2. Adjust the Line and Bus voltages to 120 V ac with a phase difference of 15°.
3. Adjust the **DELTA V LIMIT** control, **PHASE ANGLE LIMIT** control, and **UPPER VOLTAGE LIMIT** control fully clockwise.
4. Adjust the **LOWER VOLTAGE LIMIT** control fully counter-clockwise.
5. Slowly adjust the frequency difference between the Line and Bus.
6. The **DELTA F LIMIT OK** LED should extinguish as the frequency difference passes ± 0.25 Hz ± 0.025 Hz.

TYPICAL VOLTAGES

■ NOTE: Points are on the Phase Board, unless noted.

FROM	TO	CONDITION	VOLTAGE
D44 (Cathode)	D45 (Cathode)	120 V ac Input to Bus	40 V ac
D49 (Cathode)	D48 (Cathode)	120 V ac Input to Line	40 V ac
TP6	TP1	120 V ac on Line or Bus	+24 V dc
TP6	TP3	120 V ac on Line or Bus	-24 V dc
TP6	TP4	120 V ac on Line or Bus	-15 V dc
TP6	TP2	120 V ac on Line or Bus	+15 V dc
TP6	TP5	120 V ac on Line or Bus	+10 V dc
TP6	U5 - Pin 13	120 V ac on Line or Bus	+7.5 V dc approx.
TP6	U5 - Pin 9	120 V ac on Line or Bus	+7.5 V dc approx.
TP6	TP11	100 V ac on Line and Bus 0° Phase Shift	0 V
TP6	TP11	50 V ac on Line or Bus	+10 V dc
TP6	T2-4	120 V ac on Line	6 V ac
TP6	T1-4	120 V ac on Bus	6 V ac
TP6	TP6*	120 V ac on Bus	+6 V dc
TP6	U2 - Pin 13*	120 V ac on Line or Bus	+5.25 V dc ±14.5%
TP6	TP2*	120 V ac on Line or Bus	±14 V dc
TP6	TP7*	120 V ac on Line	+6 V dc
TP6	U2 - Pin 9*	120 V ac on Line or Bus	+5.25 V dc ±14.5%
TP6	TP1*	120 V ac on Line or Bus	±14 V dc
TP6	TP6*	120 V ac on Bus	+6 V dc
TP6	U2 - Pin 2*	120 V ac on Line or Bus	+6.25 V dc ±12%
TP6	TP5*	120 V ac on Line or Bus	±14 V dc
TP6	U2 - Pin 5*	120 V ac on Line or Bus	+6.25 V dc ±12%
TP6	TP7*	120 V ac on Line	+6 V dc
TP6	TP4*	120 V ac on Line or Bus	±14 V dc
TP6	TP8	Line and Bus Inputs 180° out of phase	+10 V dc
TP6	TP8	Line and Bus Inputs in phase	0 V

* On Voltage Board

FROM	TO	CONDITION	VOLTAGE
TP6	TP7	Line and Bus Inputs 180° out of phase	±14 V dc
TP6	TP7	Line and Bus Inputs in phase	0 V
TP6	U6 - Pin 14	120 V ac on Line or Bus	2 V ±2 approx.
TP6	U6 - Pin 1	120 V ac on Line or Bus	6 V ±6 approx.
TP6	U7 - Pin 13	120 V ac on Line and Bus when timer times out	+15 V approx.
TP6	U7 - Pin 12	120 V ac on Line and Bus Both inputs in phase.	+15 V approx.
TP6	U6 - Pin 12*	120 V ac on Line or Bus	+1.75 V dc ±72% approx.
TP6	TP7*	120 V ac on Line	+6 V dc
TP6	U6 - Pin 14*	120 V ac on Line or Bus	1 or 13 V dc
TP6	TP6*	120 V ac on Bus	+6 V dc
TP6	U10 - Pin 3*	120 V ac on Line or Bus	+1.75 V dc ±72% approx.
TP6	U10 - Pin 6*	120 V ac on Line or Bus	±13 V dc
TP6	D15 Anode	All LEDs lit on front panel	+1.5 V
TP6	TP3*	Line 120 V ac Bus 115 V ac Delta V Range 1 - 5	+2.5 V
TP6	U5 - Pin 6*	120 V ac on Line or Bus	±13 V dc
TP6	U5 - Pin 3*	120 V ac on Line or Bus	+6 V ±67%
TP6	TP1**	Line and Bus Input Frequency Difference 0.5 Hz	+10 V dc

* On Voltage Board

** On Delta F Board

▲ CAUTION: Any attempt to measure resistance between points on the printed circuit board is likely to cause damage to the unit.

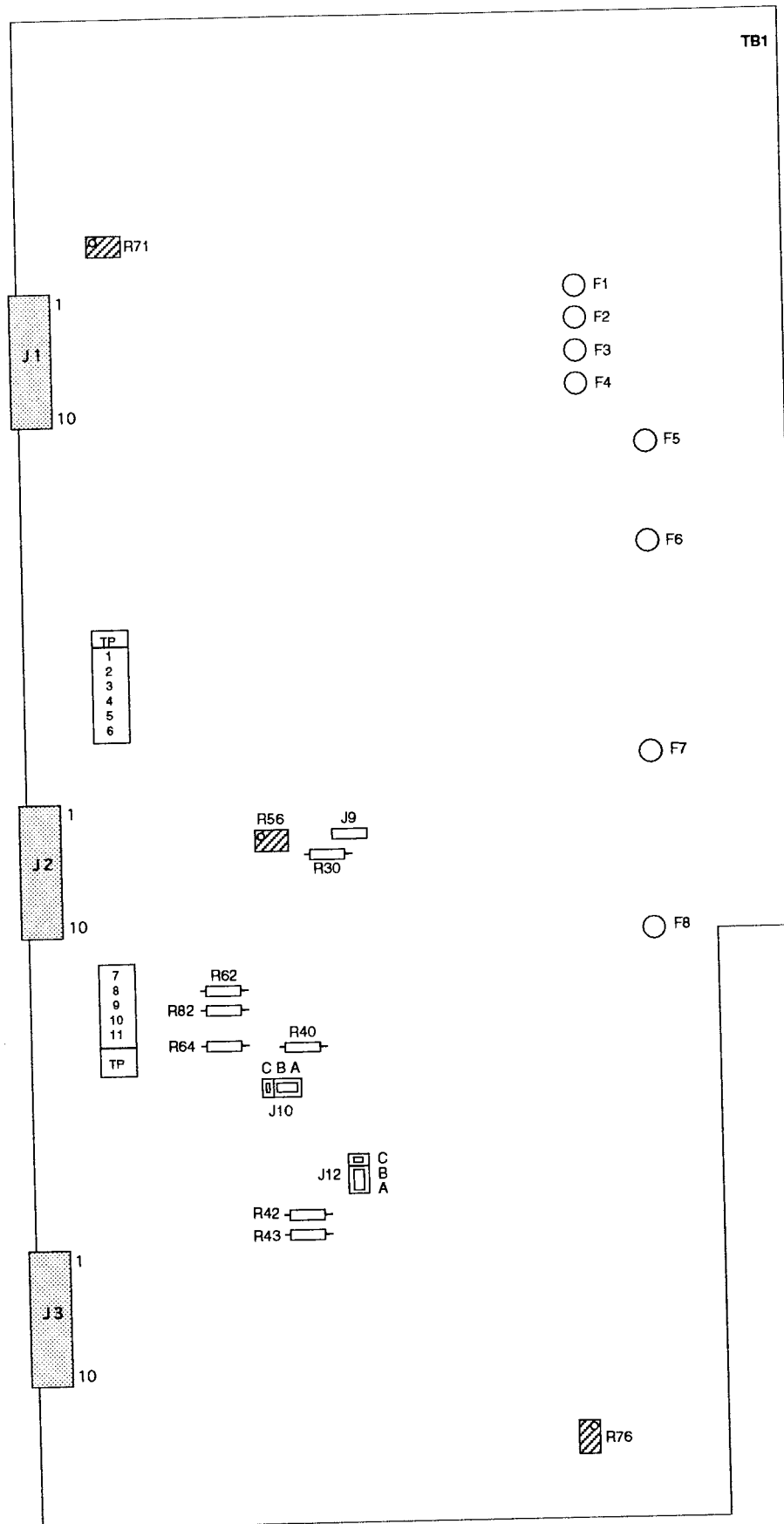
CALIBRATION

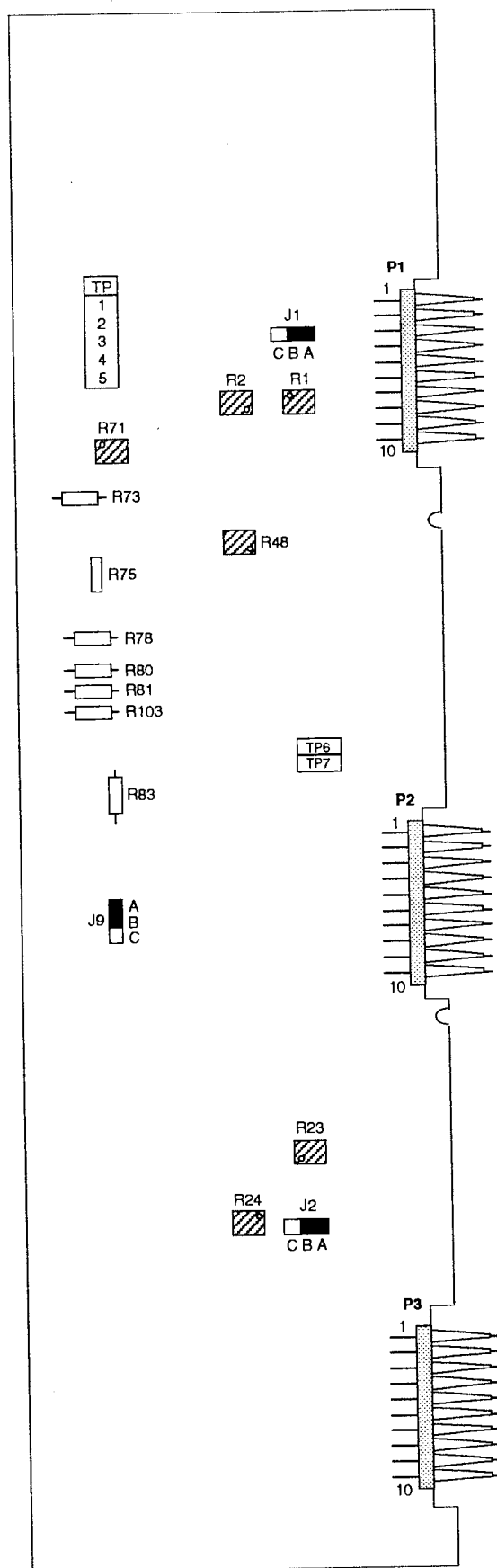
■ **NOTE:** The M-0359 unit has been fully calibrated at the factory using highly sophisticated, computer-controlled test equipment. There is no need to re-calibrate the units before initial installation. Further calibration is only necessary if a component was changed during a repair procedure. If calibration becomes necessary, it should be performed before mounting the M-0359 in a rack, since the top cover of the unit must be removed to reach calibration points. Refer to Figure 2 External Connections, Figure 3 Phase Board Component Location for Calibration and Range Resistors and Figure 4 Voltage Board Component Location for Calibration and Range Resistors.

AC TO DC CONVERTER

The ac to dc converter consists of quad op amp U1 with potentiometers R1, R2, R23 and R24 providing calibration for the Line and Bus inputs.

1. Supply 120 V ac, 60 Hz to Bus input TB1-1 and TB1-2, noting that TB1-1 is the HOT terminal.
2. Continuously monitor the Bus input to assure that the 120 V ac supply remains steady.
3. Place the positive lead of the dc voltmeter on Test Point 7 on the Voltage Board.
4. Place the negative lead on Test Point 6 on the Phase Board.
5. Adjust potentiometer R24 (Line Offset Trimmer) to read 0.00 V dc.
6. Disconnect power to the Bus input TB1-1 and TB1-2.
7. Supply 120 V ac, 60 Hz to the Line input TB1-3 and TB1-4, noting that TB1-4 is the HOT terminal.
8. Place the positive lead of the dc voltmeter on Test Point 6 on the Voltage Board.
9. Place the negative lead on Test Point 6 on the Phase Board.
10. Adjust potentiometer R2 (Bus Offset Trimmer) to read 0.00 V dc.
11. Supply 120 V ac, 60 Hz to Bus input TB1-1 and TB1-2, noting that TB1-1 is the HOT terminal.
12. Continuously monitor the Bus input to assure that the 120 V ac supply remains steady.
13. Increase the Line input to 130 V ac.
14. Adjust potentiometer R1 (Bus Voltage Trimmer) to read 6.00 V dc.
15. Decrease the Bus input to 100 V ac; the dc voltmeter should read 5.00 V dc.
16. Increase the Bus input to 130 V ac.
17. Decrease the Line input to 120 V ac.

**FIGURE 3 Phase Board Component Location for Calibration and Range Resistors**

**FIGURE 4 Voltage Board Component Location for Calibration and Range Resistors**

18. Continuously monitor the Line input to assure that the 120 V ac supply remains steady.
19. Place the positive lead of the dc voltmeter on Test Point 7 on the Voltage Board.
20. Place the negative lead on Test Point 6 on the Phase Board.
21. Adjust potentiometer R23 (Line Voltage Trimmer) to read 6.00 V dc.
22. Decrease the Line input to 100 V ac; the dc voltmeter should read 5.00 V dc.

ABSOLUTE VALUE DIFFERENCE AMPLIFIER

Components U3, U4, and U11 form this circuit on the Voltage Board.

1. Supply 120.0 V to TB1-1 and TB1-2, noting that TB1-1 is the HOT terminal.
2. Supply 120.0 V to TB1-3 and TB1-4, noting that TB1-4 is the HOT terminal.
3. Place the positive lead of the dc voltmeter on Test Point 3 on the Voltage Board.
4. Place the negative lead on Test Point 6 on the Phase Board.
5. Adjust potentiometer R71 (Delta V Offset Trimmer) to read 0.001 V dc.
6. Supply voltage to the Bus and Line input terminals according to the values in Table 1.
9. Continuously monitor the voltage to ensure that they remain steady.
10. Place the positive lead of the dc voltmeter on Test Point 3 on the Voltage Board.
11. Place the negative lead on the Test Point 6 on the Phase Board.
12. Adjust potentiometer R48 (Delta V Trimmer) on the Voltage Board to read the voltage indicated in Table 1.

Delta V Range	Bus Input TB1-1 (HOT) TB1-2 (NEUTRAL)	Line Input TB1-3 (NEUTRAL) TB1-4 (HOT)	Voltmeter Reading
1 - 5	115 V ac	120 V ac	2.50 V dc
2 - 10	110 V ac	120 V ac	5.00 V dc
3 - 15	110 V ac	125 V ac	7.50 V dc
4 - 20	110 V ac	130 V ac	10.00 V dc
5 - 25	105 V ac	130 V ac	2.50 V dc
6 - 30	105 V ac	135 V ac	2.25 V dc
10 - 50	90 V ac	140 V ac	10.00 V dc

TABLE 1 Delta V Calibration

PHASE ANGLE

1. Place a clip lead between TB1-1 and TB1-4.
2. Place a second clip lead between TB1-2 and TB1-3.
3. Supply 120 V ac, 60 Hz to Bus inputs TB1-1 and TB1-2, noting that TB1-1 is the HOT terminal.
4. Attach the positive lead of the dc voltmeter to Test Point 11 on the Phase Board.
5. Attach the negative lead to Test Point 6 on the Phase Board.
6. Adjust R71 (Phase Angle Trimmer) to obtain the lowest possible voltage reading (less than 1 mV dc).
7. Move the positive test lead of the dc voltmeter to Test Point 7 on the Phase Board.
8. Adjust R76, (Phase Angle Offset Trimmer) until the voltmeter reads 0 V dc ± 0.020 V.

DELTA F

The Delta F function consists of components U1 and U2 on the Delta F Board.

1. Set the front panel **DELTA F LIMIT** control to 0.3 Hz.
2. Place a clip lead between TB1-1 and TB1-4.
3. Place a second clip lead between TB1-2 and TB1-3.
4. Provide 120 V ac to the Bus inputs TB1-1 and TB1-2, noting that TB1-1 is the HOT terminal.
5. Attach the positive lead of the voltmeter to TP1 on the Delta F Board.
6. Attach the negative lead to Test Point 6 on the Phase Board.
7. Adjust R10 to get the lowest possible reading (less than 1 mV dc).
8. Remove the clips, and supply 118 V to the Line inputs at 60.500 Hz.
9. Adjust R11 to get 10.000 V dc.
10. Attach a 1.00 K $\pm 1\%$ resistor from TB3-D to TB3-E.
11. Place a current measuring device from TB3-C to TB3-D.
12. Adjust R21 to get 1.00 mA ± 0.05 mA.

HOW TO CHANGE RANGES

- Follow steps 1 through 5 in the **COMPONENT REPLACEMENT PROCEDURE** section using the equipment specified.
- Referring to the tables below and to the **SELECTED RESISTORS** section of the **PARTS LIST**, choose the correct resistor value or jumper wire. Use 20 gauge insulated wire for all jumpers. Refer to Figures 6 and 7 for the location of these parts.
- Refer to the **CALIBRATION** section after replacing any components.

DELTA V LIMIT (VOLTAGE BOARD)

	R81	R48	R73	R80	R78	R50	R103	Phase
								R20
1 - 5	11 K	50 K	182 K	open	open	180 K	open	1.13 K
2 - 10	11 K	50 K	182 K	5.62 K	open	180 K	open	1.13 K
3 - 15	11 K	50 K	182 K	5.62 K	1.87 K	180 K	open	1.13 K
4 - 20	11 K	50 K	182 K	5.62 K	1.87 K	180 K	jumper	1.13 K
5 - 25	11 K	10 K	35.7 K	open	open	180 K	open	6.81 K
6 - 30	11 K	10 K	24.9 K	open	open	180 K	open	6.81 K
10 - 50	Open	20 K	71.5 K	open	open	91 K	jumper	1.13 K

PHASE ANGLE LIMIT PHASE BOARD

Range	R62	R64	R82
30°	16.5 K	12.7 K	Open
45°	16.5 K	Open	Open
60°	48.7 K	Open	Open
90°	10.0 K	Open	0 Ω

PHASE LIMIT REDUCTION RATIO PHASE BOARD

Nominal Value	R40*	J10**
1/1.5	5.90 K	B&C
1/2	3.01 K	B&C
1/4	1.0 K	B&C
1/5	750 Ω	B&C
4/5	12.1 K	B&C
None		A&B

* ■ NOTE: Selected at Pretest.

** Two-positions hunt on the phase board.

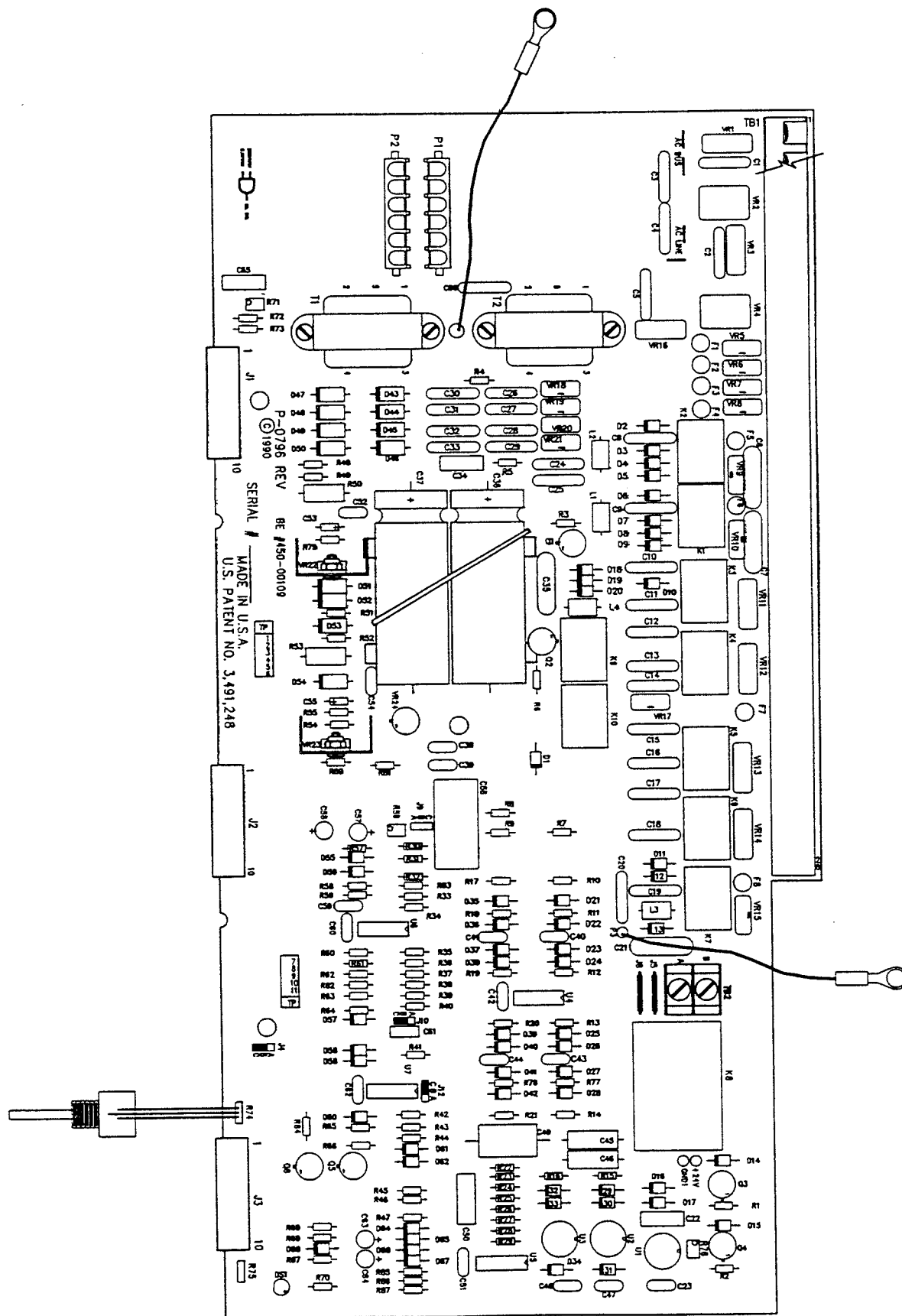


FIGURE 5 Phase Board Component Location

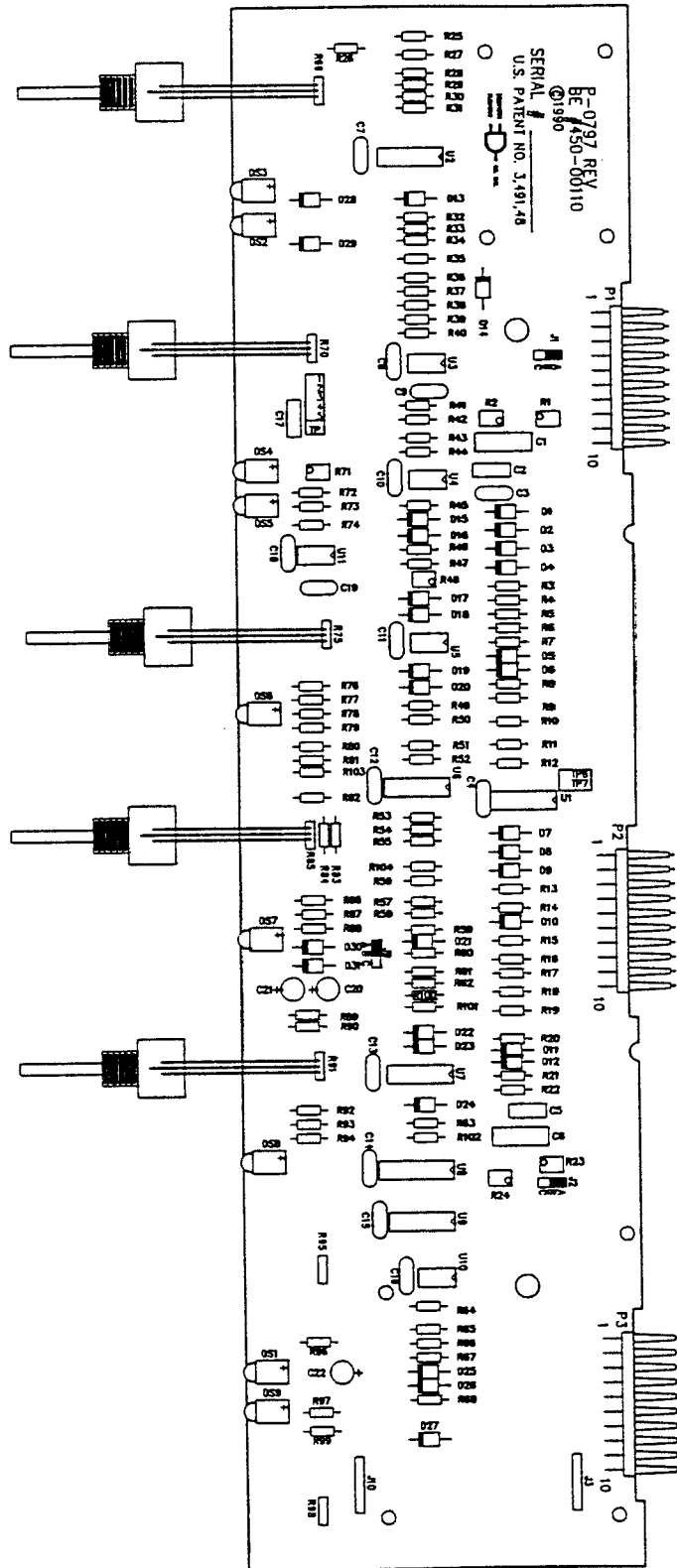


FIGURE 6 Voltage Board Component Location

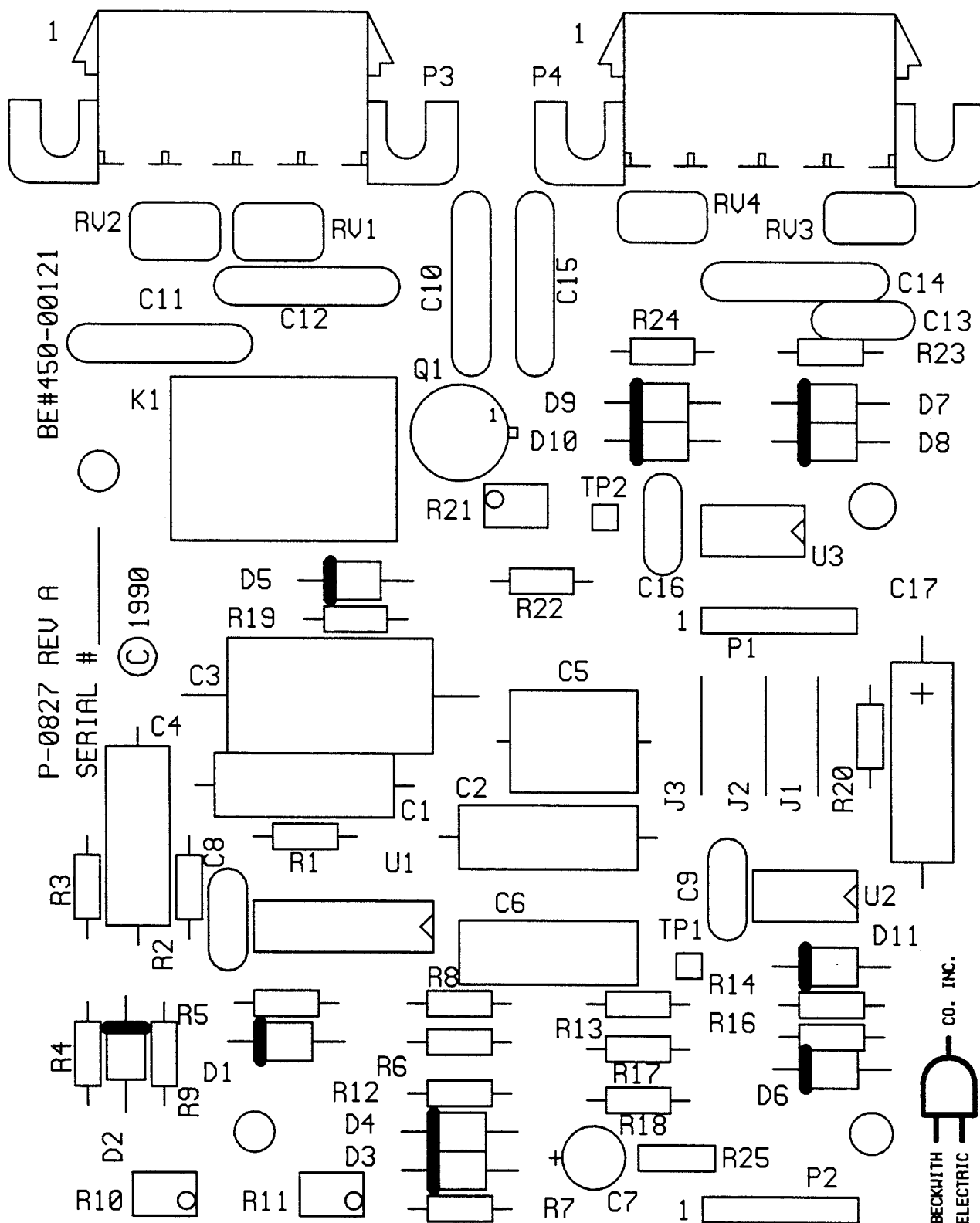


FIGURE 7 Delta F Board Component Location

PARTS LIST

M-0359 Syncrocloser® Check Plus

This list includes all electrical and mechanical parts which could conceivably either require replacement or be lost. The **COMPONENT DESIGNATION** is the same as that appearing on schematics or referred to in Instruction Books.

The **BECO NUMBER** refers to an index maintained by the company. This lists the currently available device which may be substituted even though the device originally supplied is obsolete and no longer available. Parts marked by an asterisk* are not available from other sources. Either the original component or a current substitute will be carried in stock by Beckwith Electric.

Parts not marked with an asterisk are normally available from an electronics components house. Those parts or a current substitute will normally be available from Beckwith Electric stock.

In either case, when parts are ordered from Beckwith Electric, we will be responsible for supplying the current replacement in the shortest possible time.

Sufficient detailed description is also given to permit purchasing from an electronics parts house, providing the part is of equal or better quality to insure reliable operation. This may require some interpretation of specifications which may be avoided by direct purchase from Beckwith Electric using the **BECO NUMBER**.

Note that in a few instances, components are selected in final test. Procedures described in the **TEST PROCEDURES** section must be followed in replacing these components.

All resistors are 1/2 W unless noted.

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
PHASE BOARD, B-0381		
	450-00109*	Printed Circuit Board, P-0796
C1,C2	000-00904	Capacitor, Ceramic Disk, 0.01 μ F $\pm$ 20%, 1 kV
C3-C5, C8-C20, C24-C33, C66	000-00939	Capacitor, Ceramic Disk, 0.0047 μ F $\pm$ 20%, 3 kV
C6, C7, C21, C35	000-00905	Capacitor, Ceramic Disk, 0.05 μ F +80/-20%, 600 V
C22	000-00845	Capacitor, Polyester, 0.068 μ F $\pm$ 10%, 250 V
C23, C40-C44, C47, C48, C51, C52, C54, C60, C62	000-00917	Capacitor, Ceramic Disk, 0.01 μ F $\pm$ 20%, 50 V
C34, C65	000-00811	Capacitor, Polyester, 0.1 μ F $\pm$ 10%, 100 V
C36, C37	000-00410	Capacitor, Electrolytic, 1900 μ F +75/-10%, 50 V

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
C38,C39,C59	000-00932	Capacitor, Ceramic Disk, 0.1 μ F $\pm$ 20%, 50 V
C45,C46	010-00420	Capacitor, Polycarbonate, 0.022 μ F $\pm$ 10%, 50 V
C49	000-00705	Capacitor, Polyester, 0.27 μ F $\pm$ 10%, 50 V
C50	000-00843	Capacitor, Polyester, 0.39 μ F $\pm$ 5%, 100 V
C53,C55	000-00505	Capacitor, Tantalum, 1 μ F $\pm$ 10%, 50 V
C56	000-00847	Capacitor, Polyester, 10 μ F $\pm$ 10%, 63 V
C57	000-00553	Capacitor, Tantalum, 2.2 μ F $\pm$ 10%, 25 V
C58	0000-00018	Capacitor, Electrolytic, 1.5 μ F $\pm$ 20%, 50 V
C61	000-00934	Capacitor, Ceramic Disk, 0.0047 μ F $\pm$ 10%, 50 V
C63, C64	000-00559	Capacitor, Tantalum, 6.8 μ $\pm$ 20% 50 V
D1,D10,D16,D17,D21, D22-D42,D55,D57-D61, D66-D68	400-00224	Diode, 1N4148
D2,D3,D5-D7,D9,D11, D12,D14,D19,D20,D56,	400-00211	Diode, 1N5061
D4,D8,D13,D18	400-00061	Diode, Zener, 36 V $\pm$ 5%, 1N5365B
D15	400-00004	Diode, Zener, 10 V $\pm$ 5%, 1N758A
D43-D50,D52,D53	400-00213	Diode, 1N5626
D51,D54	400-00095	Diode, 43 V, 1N5367B
D62,D64,D65	400-00225	Diode, FHD333
D63		Not Used
F1-F8	420-00725	Fuse, Plug-In, 1/2 A, 125 V, Littelfuse 273.500
FH1-FH8	420-00722	Fuse Holder, Plug-In, Vertical
J1-J3	420-00286	Socket, Right Angle, 10-Position, 0.156 Center
J4,J10,J12	420-00232	Header, 36-Position, 0.1 Center

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
J5-J8,J9,J11		Not Used
K1-K7,K9,K10	430-00151	Relay, SPDT, 24 V dc, American Zettler AZ4UP-E-1C-24D
K8	430-00144	Relay, 4PDT, 24 V dc
L1-L4	410-00521	Choke, 180 MHz
P1,P2	030-00040	Header, 6-Position, AMP 641832-1
Q1-Q6	400-00300	Transistor, 2N1711
R1	180-00271	Resistor, Carbon Comp, 270 Ω $\pm$ 5%, 1/4 W
R2	180-00222	Resistor, Carbon Comp, 2.2 K $\pm$ 5%, 1/4 W
R3,R6,R47,R57,R87	180-00103	Resistor, Carbon Comp, 10 K $\pm$ 5%, 1/4 W
R4	330-00518	Resistor, Metal Film, 15.0 K $\pm$ 1%, 1/4 W
R5,R73	330-00469	Resistor, Metal Film, 5.11 K $\pm$ 1%, 1/4 W
R7,R8	330-00579	Resistor, Metal Film, 64.9 K $\pm$ 1%, 1/4 W
R9,R29	330-00502	Resistor, Metal Film, 10.2 K $\pm$ 1%, 1/4 W
R10,R14,R18,R21	330-00566	Resistor, Metal Film, 47.5 K $\pm$ 1%, 1/4 W
R11,R17,R77,R78	330-00401	Resistor, Metal Film, 1 K $\pm$ 1%, 1/4 W
R12,R20	330-00406	Resistor, Metal Film, 1.13 K $\pm$ 1%, 1/4 W
R13,R19,R29	330-00501	Resistor, Metal Film, 10.0 K $\pm$ 1%, 1/4 W
R15,R16,R67-R69	180-00203	Resistor, Carbon Comp, 20 K $\pm$ 5%, 1/4 W
R22,R23,R28	330-00602	Resistor, Metal Film, 102 K $\pm$ 1%, 1/4 W
R24,R25,R33,R34,R66	180-00104	Resistor, Carbon Comp, 100 K $\pm$ 5%, 1/4 W
R26,R27	180-00473	Resistor, Carbon Comp, 47 K $\pm$ 5%, 1/4 W
R30		Not Used
R31	330-00385	Resistor, Metal Film, 750 Ω $\pm$ 1%, 1/4 W

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
R32,R38	330-00473	Resistor, Metal Film, 5.62 K $\pm$ 1%, 1/4 W
R35,R51,R52	180-00102	Resistor, Carbon Comp, 1 K $\pm$ 5%, 1/4 W
R36	180-00244	Resistor, Carbon Comp, 240 K $\pm$ 5%, 1/4 W
R37	330-00485	Resistor, Metal Film, 7.5 K $\pm$ 1%, 1/4 W
R39	330-00270	Resistor, Metal Film, 52.3 Ω $\pm$ 1%, 1/4W
R40	330-00447	Resistor, Metal Film, 3.01 K $\pm$ 1%, 1/4 W
R41,R65	180-00273	Resistor, Carbon Comp, 27 K $\pm$ 5%, 1/4 W
R42		Not Used
R43	330-00605	Resistor, Metal Film, 110 K $\pm$ 1%, 1/4 W
R44	180-00101	Resistor, Carbon Comp, 100 Ω $\pm$ 5%, 1/4 W
R45,R46	180-00393	Resistor, Carbon Comp, 39 K $\pm$ 5%, 1/4 W
R48,R54	330-00414	Resistor, Metal Film, 1.37 K $\pm$ 1%, 1/4 W
R49,R55	330-00310	Resistor, Metal Film, 124 Ω $\pm$ 1%, 1/4 W
R50,R53	370-00010	Resistor, Wirewound, 4.7 Ω $\pm$ 5%, 2 W
R56	360-00130	Potentiometer, 2 K $\pm$ 10%, 1/4 W, Bourns 3266W-1-202
R58	180-00200	Resistor, Carbon Comp, 20 Ω $\pm$ 5%, 1/4 W
R59	180-00513	Resistor, Carbon Comp, 51 K $\pm$ 5%, 1/4 W
R60,R61,R72	330-00501	Resistor, Metal Film, 10 K $\pm$ 1%, 1/4 W
R62	330-00522	Resistor, Metal Film, 16.5 K $\pm$ 1%, 1/4 W
R63	330-00481	Resistor, Metal Film, 6.81 K $\pm$ 1%, 1/4 W
R64	330-00511	Resistor, Metal Film, 12.7 K $\pm$ 1%, 1/4 W
R70		Not Used
R71	360-00140	Potentiometer, 10 K $\pm$ 10%, 12-Turn, Bourns 3266W-1-103
R74	360-00119	Potentiometer, Cermet, 50 K $\pm$ 10%, Allen-Bradley 73B1G040S503W
R75		Not Used
R76	360-00141	Potentiometer, 20 K $\pm$ 10%, 12-Turn, 1/4 W, Bourns 3266W-1-203

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
R79-R81,R83	370-00020	Resistor, 0 Ω (Jumper)
R82,R84		Not Used
R85,R86	180-00913	Resistor, Carbon Comp, 91 K, 15%, 1/4 W
T1,T2	410-00031*	Transformer, Input, U-0086
TB1	420-00052	Terminal Block, Right Angle, 28-Position, R.D.I. 6PCR-28-001
TB2	420-00066	Terminal Block, 2-Position, Curtis CBP-2C
TB3	420-00232	Terminal Block, 8-Position, TRW 14ZY-355-18-08-001
TP1-TP11	420-00232	Header, 36-Position, 0.1 Centers
U1-U3	400-00620	Op Amp, LF255H
U4,U6	400-00639	Quad Op Amp, Fairchild μ A4136DM
U5	400-00670	Quad Gate, Exclusive OR, Motorola MC-14070BCL/BAL
U7	400-00636	Quad AND-Gate, MC14081
VR1,VR3,VR11-VR14, VR16	400-00724	Varistor, 250 V
VR2,VR4	400-00718	Varistor, 1 kV
VR5-VR10,VR15, VR17-VR21	400-00713	Varistor, 40 V
VR22	560-00008	Voltage Regulator, Adjustable, LM317T
VR23	560-00010	Voltage Regulator, Adjustable, LM337T
VR24	400-00644	Voltage Reference, National LH0070-1H
REV A		

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
VOLTAGE BOARD, B-0382		
	450-00110*	Printed Circuit Board, P-0797
C1,C6	000-00841	Capacitor, Polycarbonate, 0.18 μ F $\pm$ 5%, 100 V
C2,C5	000-00842	Capacitor, Polycarbonate, 0.68 μ F $\pm$ 5%, 250 V
C3,C9,C19	000-00903	Capacitor, Ceramic Disk, 100 pF $\pm$ 10%, 1 kV
C4,C7,C8,C10-C16,C18	000-00917	Capacitor, Ceramic Disk, 0.01 μ F $\pm$ 20%, 50 V
C17	010-00445	Capacitor, Polycarbonate, 0.1 μ F $\pm$ 10%, 100 V
C20-C22	000-00555	Capacitor, Tantalum, 4.7 μ F $\pm$ 20%, 25 V
D1-D4,D7-D10,D13-D16, D27	400-00225	Diode, Fairchild FHD333
D5,D6,D11,D12,D17-D25, D28-D31	400-00224	Diode, 1N4148
D26	400-00239	Diode, Schottky, Hewlett-Packard 5082-2810
DS1-DS9	400-00729	LED, Red, Right Angle PC Mount, IDI
J1,J2,J9	420-00232	Header, 36-Position, 0.1 Centers
J3,J10	420-00315	Socket Strip, 6-Position, 0.1 Centers
J4-J8		Not Used
P1-P3	420-00287	Header, Right Angle, 10-Position, 0.156 Centers, Molex 26-48-2106 Series 41672
R1,R23	360-00140	Potentiometer, 10 K $\pm$ 10%, 12-Turn, Bourns 3266W-1-103
R2,R24,R71	360-00141	Potentiometer, 20 K $\pm$ 10%, 12-Turn, Bourns 3266W-1-203
R3,R4,R11,R13,R14,R22	330-00568	Resistor, Metal Film, 49.9 K $\pm$ 1%, 1/4 W
R5-R8,R15,R16,R20,R21	330-00601	Resistor, Metal Film, 100 K $\pm$ 1%, 1/4 W

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
R9,R17,R51-R53,R72	330-00701	Resistor, Metal Film, 1 M $\pm$ 1%, 1/4 W
R10,R18,R49,R57,R58, R74,R92	330-00401	Resistor, Metal Film, 1 K $\pm$ 1%, 1/4 W
R12,R19	330-00589	Resistor, Metal Film, 82.5 K $\pm$ 1%, 1/4 W
R25,R39,R54	330-00501	Resistor, Metal Film, 10 K $\pm$ 1%, 1/4 W
R26	330-00526	Resistor, Metal Film, 18.2 K $\pm$ 1%, 1/4 W
R27,R38,R80,R83,R94	330-00473	Resistor, Metal Film, 5.62 K $\pm$ 1%, 1/4 W
R28,R30,R33,R34	180-00395	Resistor, Carbon Comp, 3.9 M $\pm$ 5%, 1/4 W
R29,R31,R32,R35,R65, R79,R97	180-00622	Resistor, Carbon Comp, 6.2 K $\pm$ 5%, 1/4 W
R36	330-00513	Resistor, Metal Film, 13.3 K $\pm$ 1%, 1/4 W
R37	330-00518	Resistor, Metal Film, 15 K $\pm$ 1%, 1/4 W
R40-R46	340-00002	Resistor, 20 K $\pm$ 0.1%, 1/4 W
R47	340-00001	Resistor, 10 K $\pm$ 0.1%, 1/4 W
R48	360-00142	Potentiometer, 12-Turn, Top Adjust, 50 K $\pm$ 10%, 1/4 W, Bourns 3266W-1-503
R50	180-00184	Resistor, Carbon Comp, 180 K $\pm$ 5%, 1/4 W
R55	330-00454	Resistor, Metal Film, 3.57 K $\pm$ 1%, 1/4 W
R56,R99	180-00302	Resistor, Carbon Comp, 3.0 K $\pm$ 5%, 1/4 W
R59-R63,R89,R90	180-00104	Resistor, Carbon Comp, 100 K $\pm$ 5%, 1/4 W
R87	180-00304	Resistor, Carbon Comp, 300 K $\pm$ 5%, 1/4 W
R60-R63,R89,R90	180-00104	Resistor, Carbon Comp, 100 K $\pm$ 5%, 1/4 W
R64,R84,R86,R96	180-00105	Resistor, Carbon Comp, 1 M $\pm$ 5%, 1/4 W
R66,R88	180-00103	Resistor, Carbon Comp, 10 K $\pm$ 5%, 1/4 W
R67	180-00204	Resistor, Carbon Comp, 200 K $\pm$ 5%, 1/4 W
R68	330-00647	Resistor, Metal Film, 301 K $\pm$ 1%, 1/4 W

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
R69,R70,R75,R85,R91	360-00119	Potentiometer, Cermet, 50 K $\pm$ 10%, Allen-Bradley 73B1G040S503W
R73	330-00626	Resistor, Metal Film, 182 K $\pm$ 1%
R76	330-00385	Resistor, Metal Film, 750 Ω $\pm$ 1%, 1/4 W
R77	330-00449	Resistor, Metal Film, 3.16 K $\pm$ 1%, 1/4 W
R78	330-00427	Resistor, Metal Film, 1.87 K $\pm$ 1%, 1/4 W
R81	330-00505	Resistor, Metal Film, 11 K $\pm$ 1%, 1/4 W
R82,R93	330-00516	Resistor, Metal Film, 14.3 K $\pm$ 1%, 1/4 W
R95,R98,R99-R102,R104		Not Used
R103	370-00020	Resistor, 0 Ω (Jumper)
TP1-TP7	420-00232	Header, 5-Position, 0.1 Centers
U1,U6	400-00665	Quad Op Amp, LM224J
U2	400-00639	Quad Op Amp, 4136DC
U3,U4,U11	560-00011	Op Amp, LM108J8
U5,U10	560-00012	Op Amp, MC1741
U7,U9	400-00636	Quad AND-Gate, MC14081
U8	540-00059	Hex Inverter, CD4049
REV A		

DELTA F BOARD, B-0346

	450-00121*	Printed Circuit Board. P-0827
C1	010-00418	Capacitor, Polycarbonate, 0.47 μ F $\pm$ 10%, 50 V, CDE WCP-05P47
C2	000-00717	Capacitor, Polyester, 0.027 μ F $\pm$ 10%, 50 V, CDE WMF-1S27
C3	010-00419	Capacitor, Polycarbonate, 2.0 μ F $\pm$ 1%, 50 V, F-DYNE MPC23

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
C4	010-00420	Capacitor, Polycarbonate, 0.22 μ F $\pm$ 10%, 100 V, CDE WMF-1S22
C5	010-00437	Capacitor, Polycarbonate, 1.5 μ F $\pm$ 10%, 50 V F-DYNE, MPC13-1.5-50-10
C6	000-00835	Capacitor, Polyester, 1 μ F $\pm$ 10%, 63 V Roederstein, MKT-1822-510-06-5
C7	000-00555	Capacitor, Tantalum, 4.7 μ F $\pm$ 20%, 25 V, Panasonic ECSF25E4R7
C8,C9,C13,C16	000-00917	Capacitor, Ceramic Disk, 0.01 μ F $\pm$ 20%, 50 V, Centralab UK50-103
C10-C12,C14,C15	000-00939	Capacitor, 0.0047 μ F $\pm$ 20%, 3 kV
C17	000-00533	Capacitor, 150 μ F $\pm$ 20 V dc
D1,D2,D11	400-00225	Diode, Fairchild, FD333
D3-D10	400-00224	Diode, 1N4148
K1	430-00151	Relay, 24 V, American Zettler AZ4-UP-E-1C-24V
Q1	400-00300	Transistor, NPN, 2N1711
P1,P2	420-00232	Header, 36-Position, 0.1 Centers
P3, P4	030-00039	Header, Assembly, 4-Position, AMP 2-350948-0
R1	330-00574	Resistor, Metal Film, 57.6 K $\pm$ 1%, 1/4 W
R2	330-00668	Resistor, Metal Film, 499 K $\pm$ 1%, 1/4 W
R3-R5	330-00630	Resistor, Metal Film, 200 K $\pm$ 1%, 1/4 W
R6,R8	330-00601	Resistor, Metal Film, 100 K $\pm$ 1%, 1/4 W, RN60E
R7	330-00626	Resistor, Metal Film, 182 K $\pm$ 1%, 1/4 W
R9	200-00106	Resistor, Carbon Film, 10 M $\pm$ 5%, 1/2 W
R10	360-00139	Potentiometer, 12-Turn, 100 K $\pm$ 10%, Bourns 3266W-1-104
R11	360-00142	Potentiometer, 50 K

COMPONENT DESIGNATION	BECO NUMBER	DESCRIPTION
R12	200-00204	Resistor, Carbon Film, 200 K $\pm 5\%$, 1/2 W
R13,R19	200-00203	Resistor, Carbon Film, 20 K $\pm 5\%$, 1/2 W
R14	200-00365	Resistor, Carbon Film, 3.6 M $\pm 5\%$, 1/2 W
R15		Not Used
R16	200-00513	Resistor, Carbon Film, 51 K $\pm 5\%$, 1/2 W
R17	330-00568	Resistor, Metal Film, 49.9 Ω $\pm 1\%$, 1/4 W, RN60E
R18	330-00473	Resistor, Metal Film, 5.62 K $\pm 1\%$, 1/4 W, RN60E
R20	200-00273	Resistor, Carbon Film, 27 K 5%, 1/4 W
R21	360-00141	Potentiometer, 20 K 10%, 1/4 W
R22	330-00406	Resistor, Metal Film, 1.13 K $\pm 1\%$, 1/4 W, RN60E
R23	330-00566	Resistor, Metal Film, 47.5 K $\pm 1\%$, 1/4 W, RN60E
R24	330-00401	Resistor, Metal Film, 1.0 K $\pm 1\%$, 1/4 W, RN60E
R25	360-00119	Potentiometer, 50 K $\pm 10\%$
U1	400-00665	Quad Op Amp, National, LM224J
U2,U3	560-00012	Op Amp, Motorola MC1741
VR1,VR2	400-00724	Varistor, 250 V
VR3,VR4	400-00713	Varistor, 40 V
Rev A		

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TO VOLTAGE

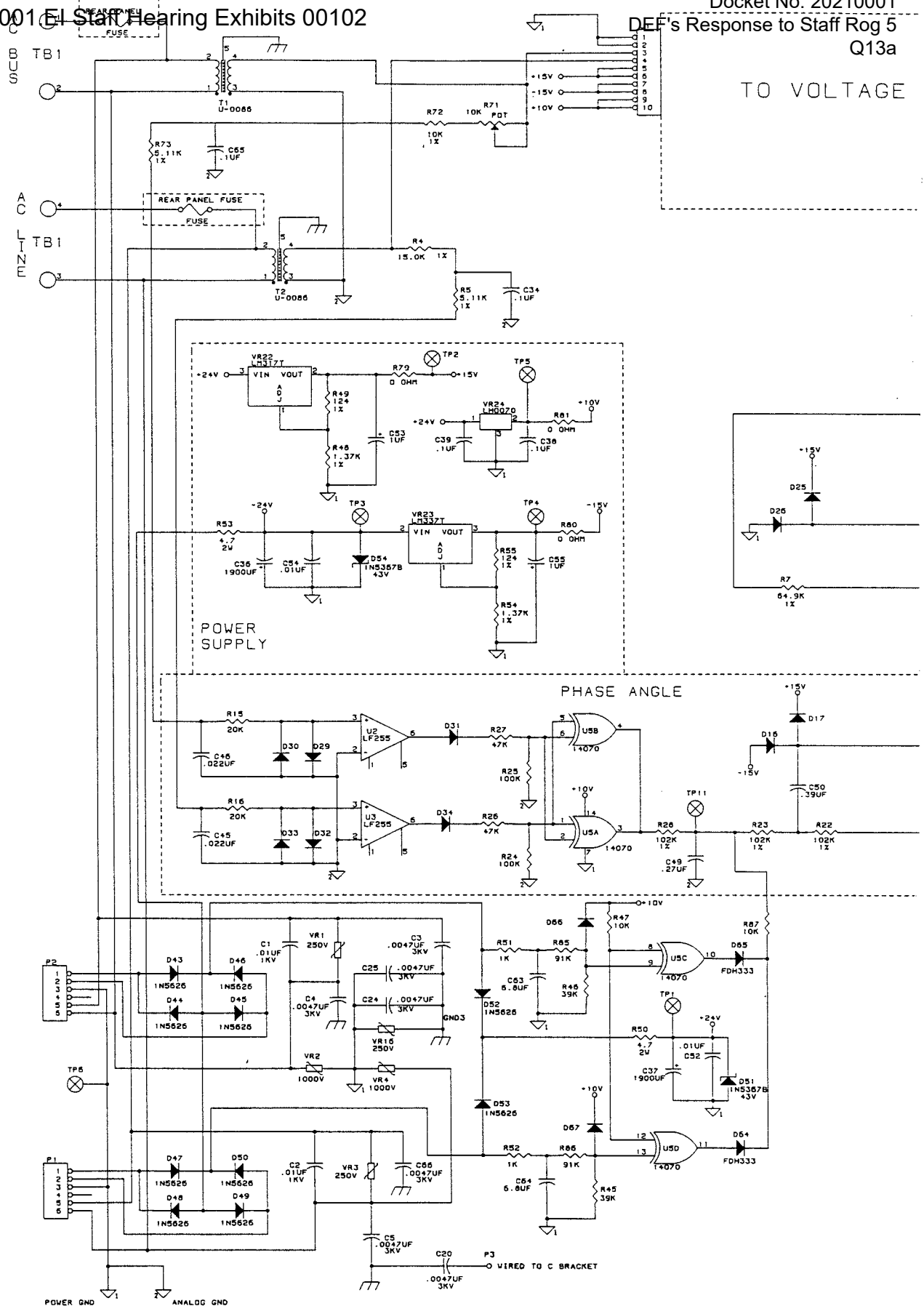
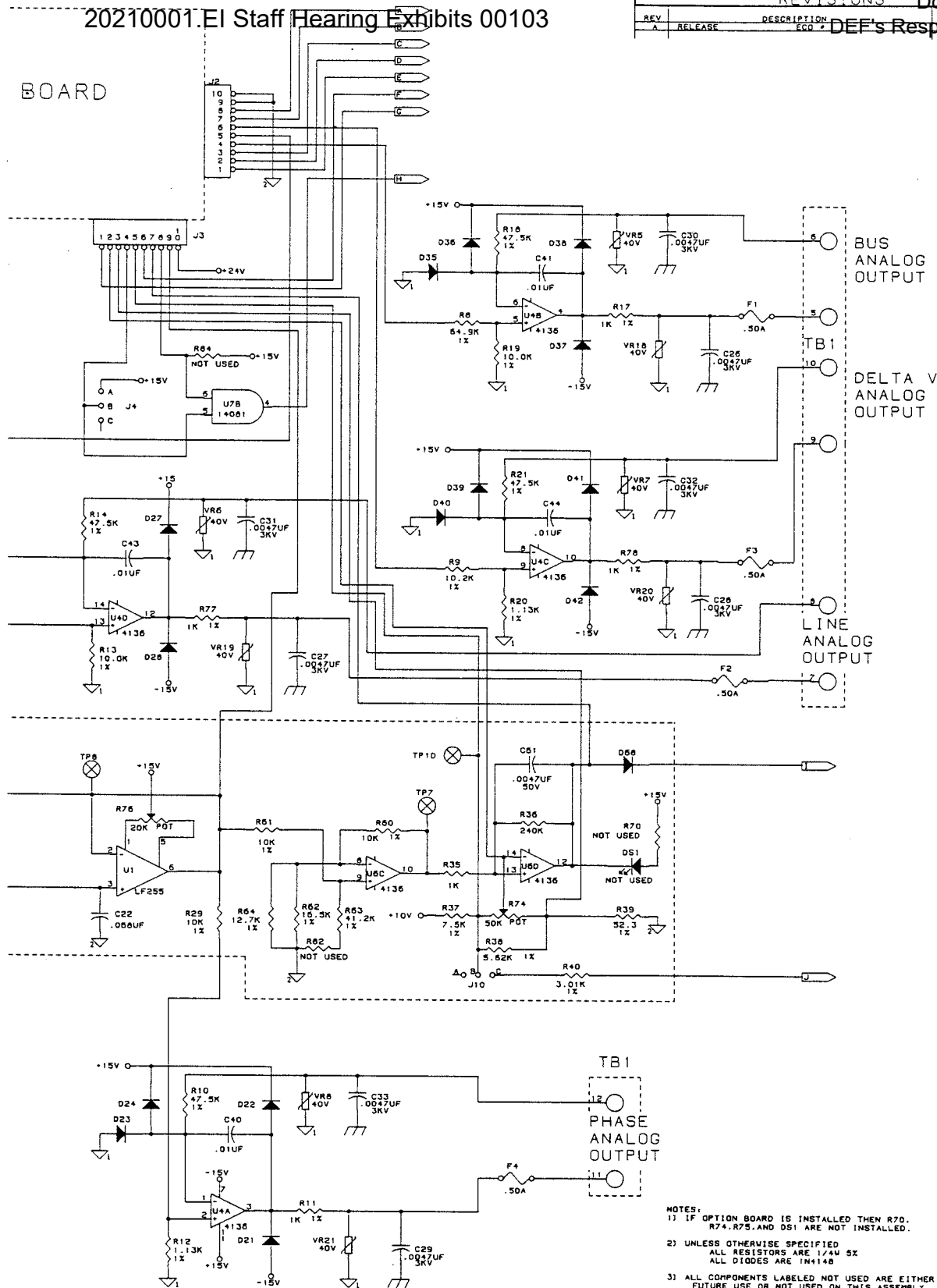


FIGURE 8a Phase Board Schematic

20210001.EI Staff Hearing Exhibits 00103

REVISIONS				Docket No. 20210001	
REV	DESCRIPTION	DATE	APPROVED	DEF's Response to Staff Rog 5	
A	RELEASE	ECG		Q13a	

BOARD



- NOTES:
- 1) IF OPTION BOARD IS INSTALLED THEN R70, R74, R75, AND DS1 ARE NOT INSTALLED.
 - 2) UNLESS OTHERWISE SPECIFIED ALL RESISTORS ARE 1/4W 5% ALL DIODES ARE 1N4148
 - 3) ALL COMPONENTS LABELED NOT USED ARE EITHER FUTURE USE OR NOT USED ON THIS ASSEMBLY

BECKWITH		CB, INC.		TITLE SCHEMATIC			
ELECTRIC				SMYROCLOSER CHECK PLUS RELAY (PHASE)			
OWN	CHK	APP	DATE	SCALE	SIZE	DRAWING NUMBER	SMT REV
KP		JMA	6/22/90	NONE	D	Y-0381	1/2 A

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FIGURE 8b Phase Board Schematic

20210001.EI Staff Hearing Exhibits 00104

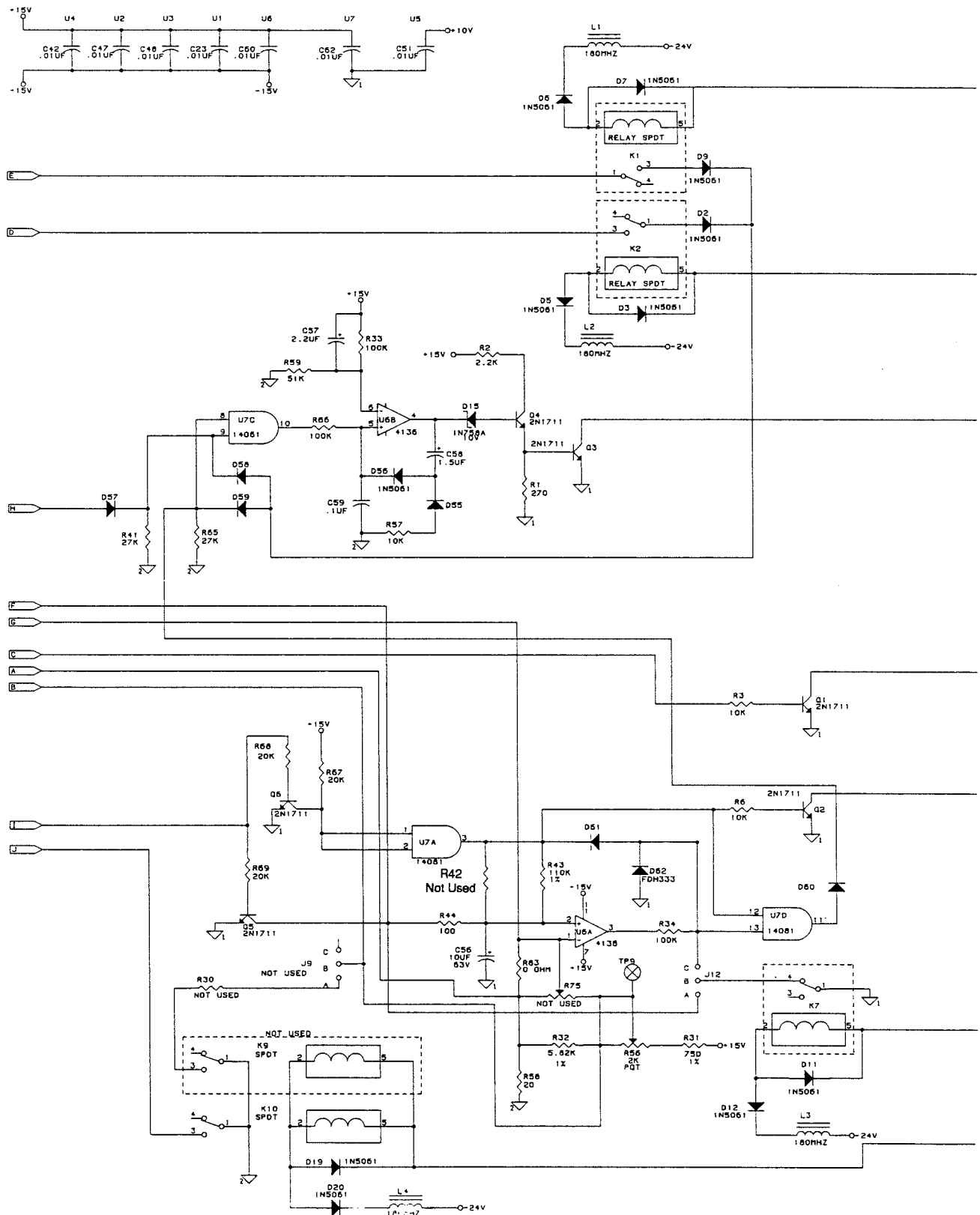
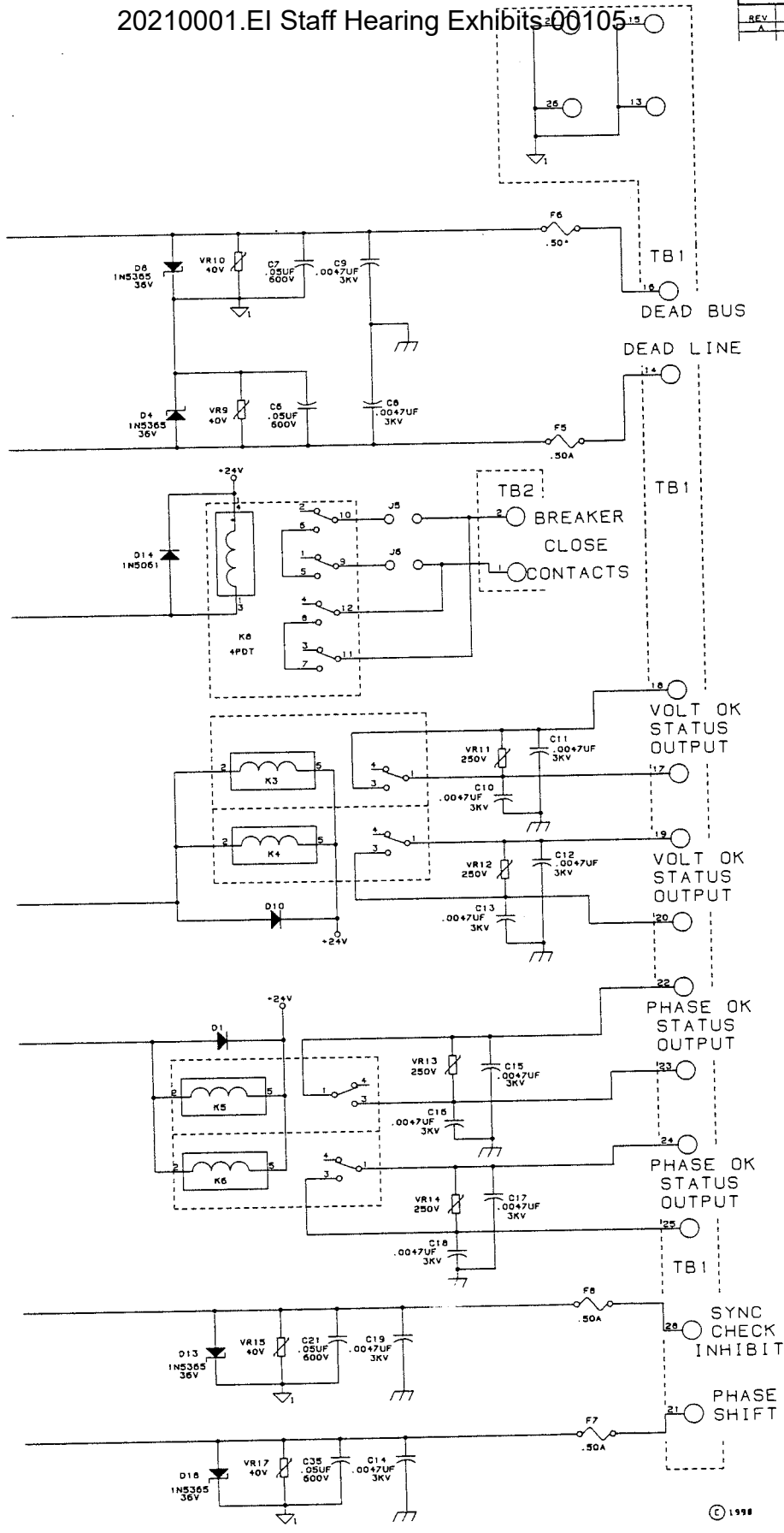


FIGURE 8c Phase Board Schematic

20210001.EI Staff Hearing Exhibits 00105

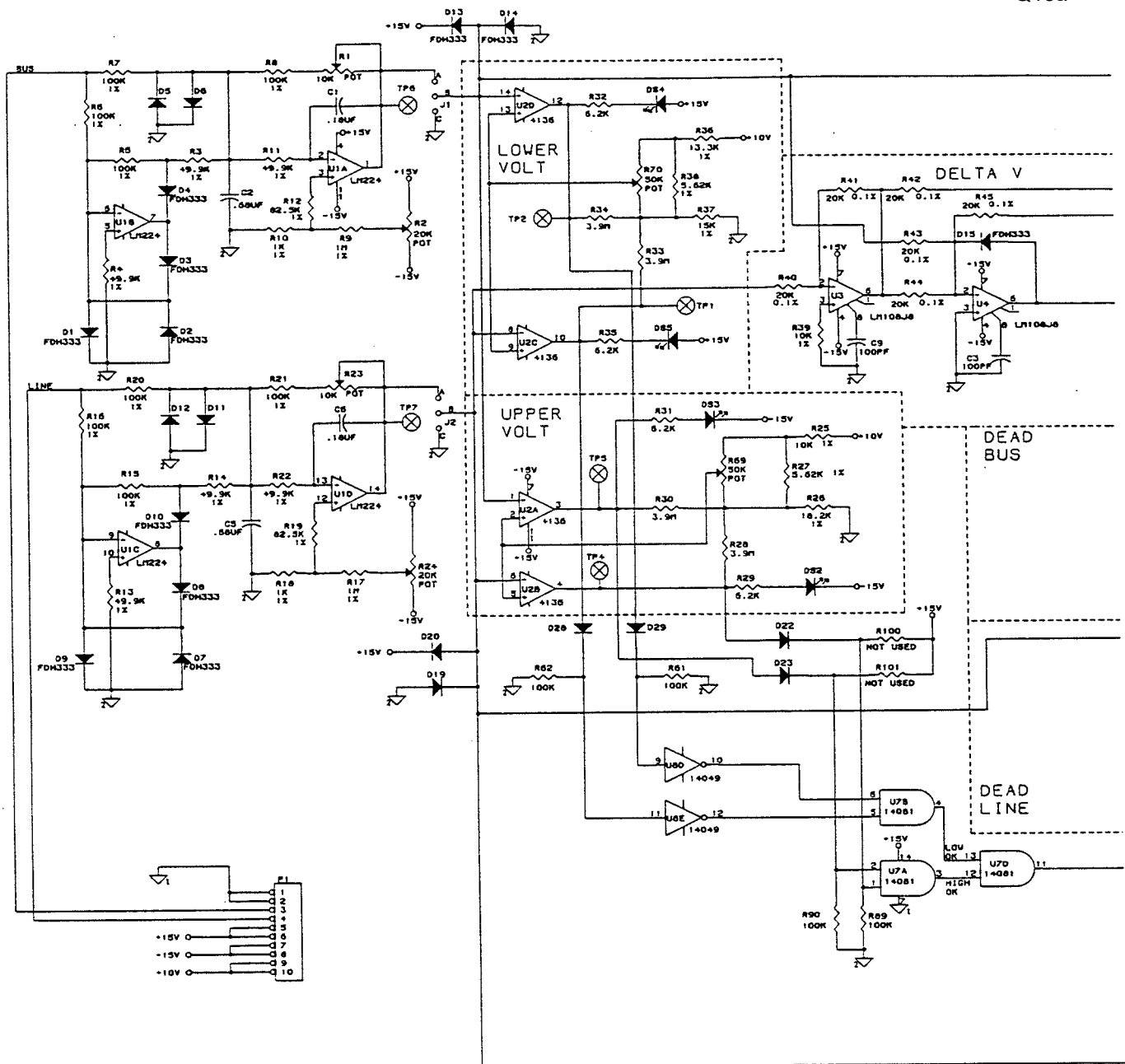
DEF's Response to Staff Rg 5

Q13a



BECKWITH ELECTRIC		CO. INC		TITLE		SCHEMATIC		SYNCHRO-CLOSER CHECK PLUS RELAY (PHASE)	
DWN	CHK	APP	DATE	SCALE	SIZE	DRAWING NUMBER	SHT	REV	
KP			6/22/90	NONE	D	Y-0381	2/2	A	

FIGURE 8d Phase Board Schematic



NOTE:
UNLESS OTHERWISE SPECIFIED, ALL DIODES ARE 1N4049

POWER GND ANALOG GND

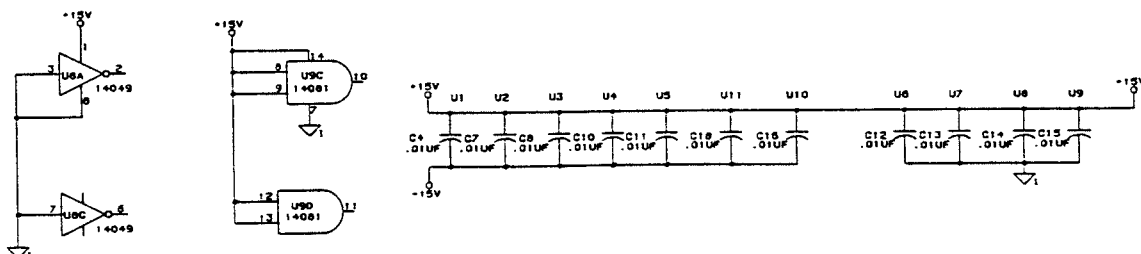
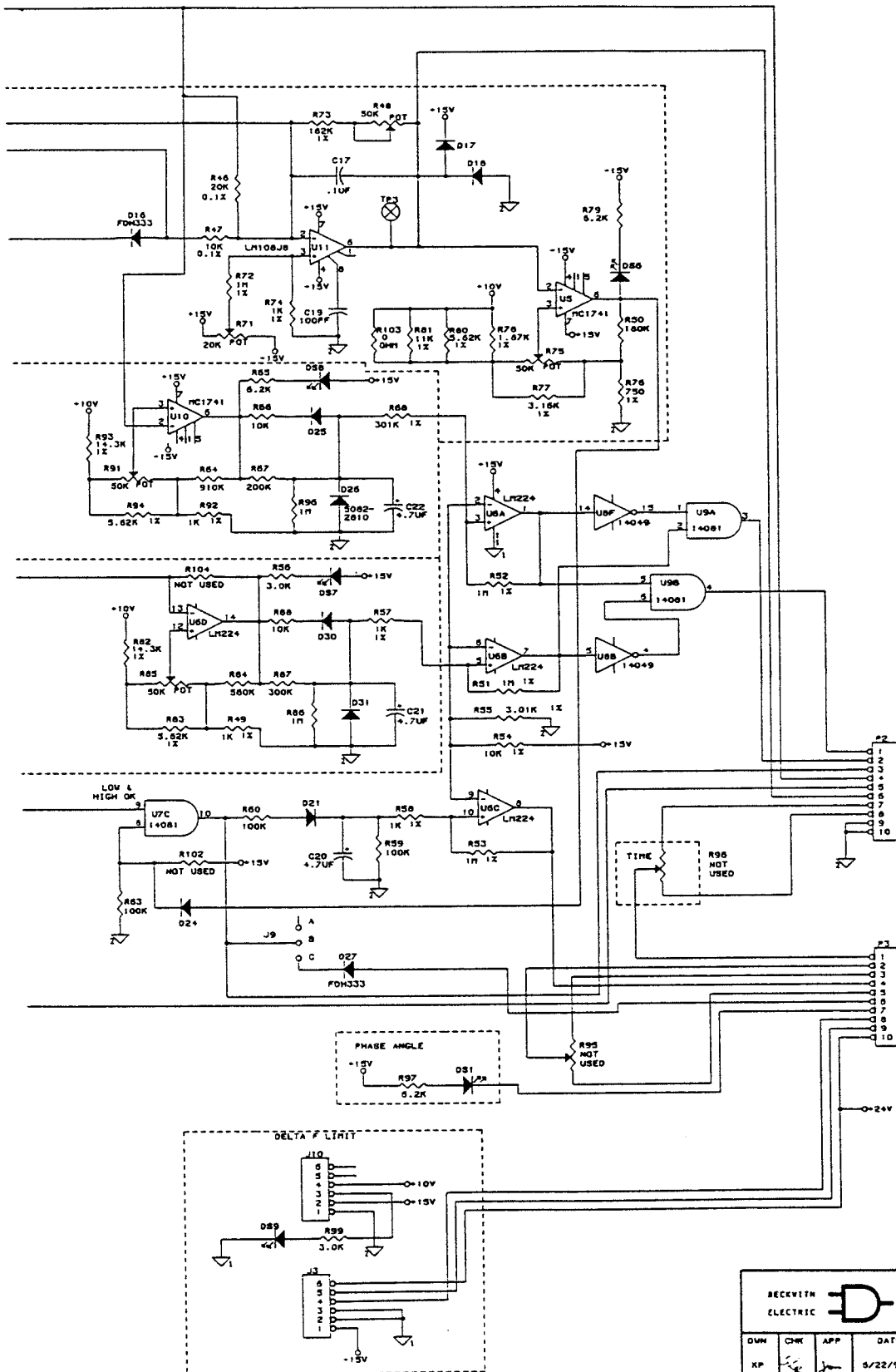


FIGURE 9a Voltage Board Schematic

REVISIONS			
REV	DESCRIPTION	ECO	DATE
1	RELEASE	ECO = 0617	1/20/90
2	REVISED ECO=0737		5/22/91

Q13a



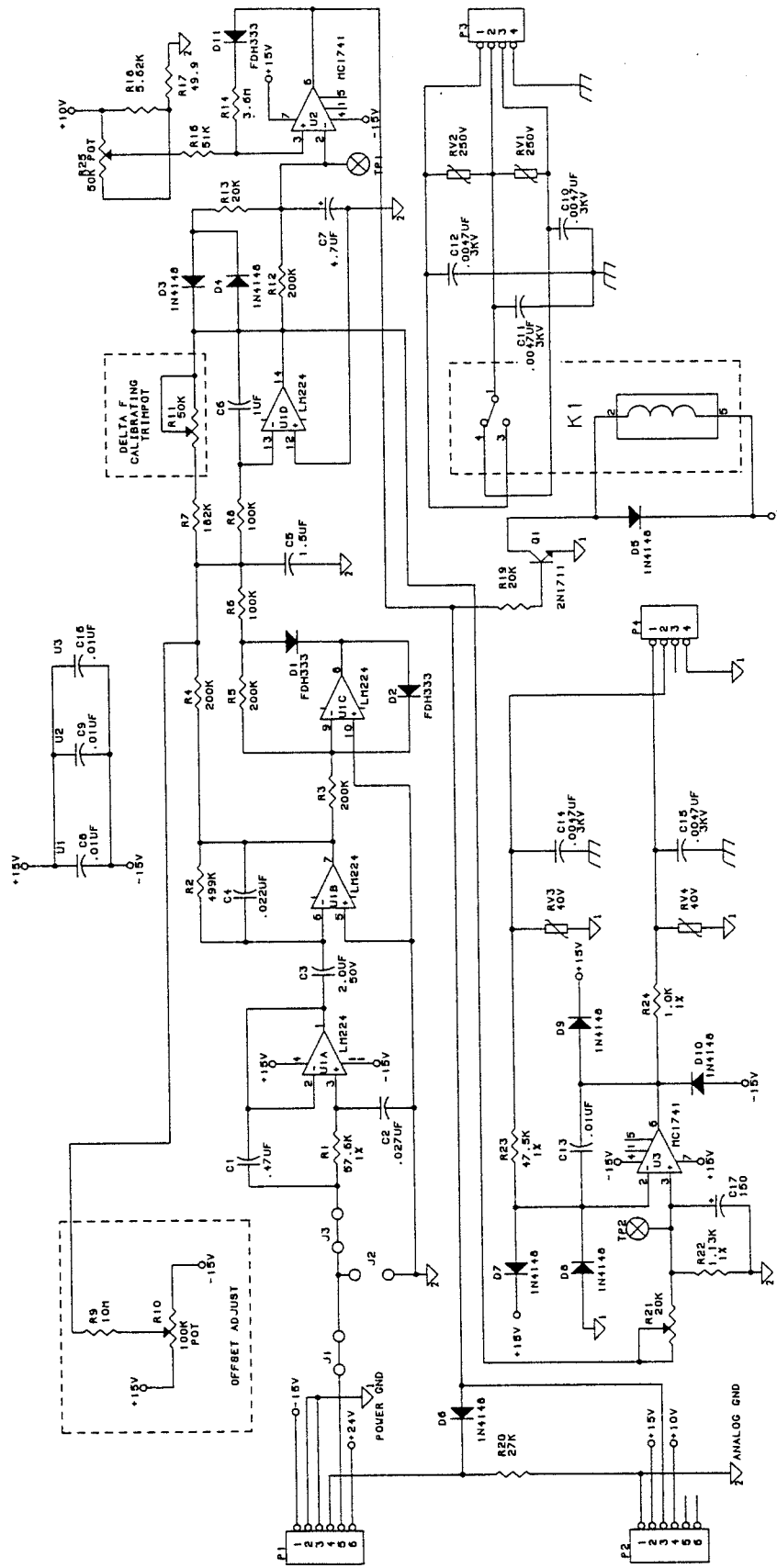
© 1998 BECKWITH ELECTRIC

BECKWITH ELECTRIC					TITLE SCHEMATIC			
SYNCHRO-CLOSER CHECK RELAY OPTION BOARD SCHEMATIC					DATE	SCALE	SIZE	DRAWING NUMBER
OWN	CHK	APP	DATE	SCALE	SIZE	DRAWING NUMBER	BHT	REV
KP			5/22/90	NONE	C	Y-0382	1	B

FIGURE 9b Voltage Board Schematic

REVISIONS

REV	DESCRIPTION	DATE	APPROVED
A	RELEASE PER ECR# 0074	8/7/90	909/2/2/1/1/1



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BECKWITH ELECTRIC		CD. INC.		TITLE SCHEMATIC	
DWN		CHK	APP	DATE	SCALE
KP				2/5/90	NONE
SIZE		DRAWING NUMBER		B Y-0345	
REV		SHEET		1	

FIGURE 10 Delta F Board Schematic

Patent

The units described in this manual are covered by U.S. Patents, with other patents pending.

Buyer shall hold harmless and indemnify the Seller, its directors, officers, agents, and employees from any and all costs and expense, damage or loss, resulting from any alleged infringement of United States Letters Patent or rights accruing therefrom or trademarks, whether federal, state, or common law, arising from the Seller's compliance with Buyer's designs, specifications, or instructions.

Warranty

Seller hereby warrants that the goods which are the subject matter of this contract will be manufactured in a good workmanlike manner and all materials used herein will be new and reasonably suitable for the equipment. Seller warrants that if, during a period of five years from date of shipment of the equipment, the equipment rendered shall be found by the Buyer to be faulty or shall fail to perform in accordance with Seller's specifications of the product, Seller shall at his expense correct the same, provided, however, that Buyers shall ship the equipment prepaid to Seller's facility. The Seller's responsibility hereunder shall be limited to replacement value of the equipment furnished under this contract.

Seller makes no warranties expressed or implied other than those set out above. Seller specifically excludes the implied warranties of merchantability and fitness for a particular purpose. There are no warranties which extend beyond the description contained herein. In no event shall Seller be liable for consequential, exemplary, or punitive damages of whatever nature.

Any equipment returned for repair must be sent with transportation charges prepaid. The equipment must remain the property of the Buyer. The aforementioned warranties are void if the value of the unit is invoiced to the Seller at the time of return.

Indemnification

The Seller shall not be liable for any property damages whatsoever or for any loss or damage arising out of, connected with, or resulting from this contract, or from the performance or breach thereof, or from all services covered by or furnished under this contract.

In no event shall the Seller be liable for special, incidental, exemplary, or consequential damages, including but not limited to, loss of profits or revenue, loss of use of the equipment or any associated equipment, cost of capital, cost of purchased power, cost of substitute equipment, facilities or services, downtime costs, or claims or damages of customers or employees of the Buyer for such damages, regardless of whether said claim or damages is based on contract, warranty, tort including negligence, or otherwise.

Under no circumstances shall the Seller be liable for any personal injury whatsoever.

It is agreed that when the equipment furnished hereunder are to be used or performed in connection with any nuclear installation, facility, or activity, Seller shall have no liability for any nuclear damage, personal injury, property damage, or nuclear contamination to any property located at or near the site of the nuclear facility. Buyer agrees to indemnify and hold harmless the Seller against any and all liability associated therewith whatsoever whether based on contract, tort, or otherwise. Nuclear installation or facility means any nuclear reactor and includes the site on which any of the foregoing is located, all operations conducted on such site, and all premises used for such operations.

Notice:

Any illustrations and descriptions by Beckwith Electric Co., Inc. are for the sole purpose of identification.

The drawings and/or specifications enclosed herein are the proprietary property of Beckwith Electric Co., Inc., and are issued in strict confidence; therefore, shall not be used as a basis of reproduction of the apparatus described therein without written permission of Beckwith Electric Co., Inc.

No illustration or description contained herein shall be construed as an express warranty of affirmation, promise, description, or sample, and any and all such express warranties are specifically excluded nor shall such illustration or description imply a warranty that the product is merchantable or fit for a particular purpose. There shall be no warranties which extend beyond those contained in the Beckwith Electric Co., Inc. terms of sale.

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BECKWITH ELECTRIC CO., INC.

6190 - 118th Avenue North • Largo, Florida 33773-3724 U.S.A.

PHONE (727) 544-2326 • FAX (727) 546-0121

marketing@beckwithelectric.com

www.beckwithelectric.com

ISO 9001:2008

STATION: 20210001-EL Staff Hearing Exhibits 00112
TYPE: Generator Protection, Synchronizing
VOLTAGE (KV): 230
DESIGNATION: UNIT#4 MAN SYNC/VOLT CHECK
BREAKER(S): 3233, 3234
DEVICE: 25/27
CATEGORY: ONLY
ACTIVE SETTING GROUP
RELAY SCHEME
S/N: 1711
FIRMWARE VER No. or FID No.

JUSTIFICATION: INSTALLATION
☐ ORIGINAL ☐ TEMP FILE COPY
RELAY MODEL M-0359
PHASE A, 3Ph or Other
B
C
PRINT CODE 5-F
LAST CALC BY:
LAST CALC DATE: 3/9/2002

THOR# Q13a
Equipment# 5600884
SHEET # 1 OF 1

SETTING NAME	SETTING	COMMENTS
PTR (/1)	1200	
UPPER VOLTAGE LIMIT	121 120.93 B / 120.94 G	251KV (+5%)
LOWER VOLTAGE LIMIT	110 109.87 B / 109.88 G	228KV (-5%)
DELTA V LIMIT	2 2.1	DELTA 4.2KV (Ph-Ph)
DEAD LINE LIMIT	50 49.87	USED (Black Start)
DEAD BUS LIMIT	50 49.94	NOT USED
PHASE ANGLE LIMIT	15 15.13 B / 345.02 G	
DELTA F LIMIT	0.06 0.06	

CASCADE W.D. 2013-3004193410 MX 2014-3004245604 CALIBRATION
ABOVE READINGS ARE AS FOUND / AS LEFT

***** All changes to this section must be reviewed by Transmission Engineering *****
(Applicable only for relay replacement or new installation performed by Construction or Maintenance).

New relay installation verification check list.

☐ Relay inputs in use verified ☐ Relay outputs in use verified ☐ Relay targets verified
☐ Final after testing - Setting file in relay is verified

Test Personnel: _____

Testing Performed
☐ Relay test software (RTS) or ☐ Manual

☐ Functional Testing Complete This relay has been tested and commissioned according to Progress Energy Procedures: Protective Relaying for Technicians, Chapter 25, Appendix B, "Minimum Requirements for Acceptance on Capital Projects".
Test Personnel: _____ Date: ____/____/____

ENG COMMENTS: Supervises Manual Closes.
(HISTORIC)

ENG REMARKS: Fill in as installed Values.
(CURRENT)

FIELD COMMENTS: _____

Underfrequency Set Points
A=59.7+12cy, B=59.4+12cy, C=59.1+12cy, D=58.8+12cy, E=58.5+12cy, F=58.2+12cy, L=59.4+10sec, M=59.7+12sec, N=59.1+8sec, NT=No Trip

***** RELAY TECHNICIAN CHECK LIST *****

1). Sign/Print your name and Date Setting Sheet
2). Record S/N & Firmware Version for IED rly's and FID for all SEL rly's
3). Markup chg's to electromechanical rly's on setting sheet
4). Download settings from IED rly's into electronic file and e-mail to: relavsettings@duke-energy.com
5). Verify complete relay model number & record if not shown
6). Return Setting Sheet to the appropriate Const./ Maint. Engineer
7). Verify all CT ratios related to this setting sheet

PEER CHECK BY: _____
ISSUED BY: PARRIS VAN SMITH INTL: _____
ISSUE DATE: 9/12/2014

INSTALLATION BY: Michael L. Benson DATE 11/23/2014
PRINT NAME MICHAEL L. BENSON

RTS Relay Test Results

Powered by:



Lib Routine: M-0359.FL_LIB	AF/AL: AF	Pass/Fail: PASS
Lib Version: 1.0	Test Date: 03/11/2018	
Relay Data:		
TESTED_BY: R.GERHARDT	DIVISION: FL-NORTH COASTAL	
SUBSTATION: CRPL-S4 604	TERMINAL: UNIT 4 syncloser M0359	
PRINT_CODE: 5F	PHASE_ZONE: ABC	
RELAY_MANF: BECKWITH	RELAY_TYPE: M-0359	
MODEL_STYLE: M-0359	IEEE_DEVICE:	
IL_IB:	SERIAL_NUMBER: NA	
FIRMWARE:	RELAY_ID: 5600884	
WO_NUMBER:	REASON_FOR_TEST: MAINTENANCE	
NERC_AUDITABLE:	NERC_SUBNUM:	
MAINT_INTERVAL:	PREVIOUS_TESTDATE:	
CURRENT_TESTDATE: 3/11/2018	NEXT_TESTDATE:	
TESTSET_CALDATE:	APPROVED_BY:	
Global Defines:		
Routine Notes:		
Relay Settings Used for Testing:		
TEST_VOLTS= 115	CLOSE_ANGLE= 15	DEAD_LINE= 50
DEAD_BUS= 50	LV_LIMIT= 110	UV_LIMIT= 121
NORM_FREQ= 60	FREQ_DIFF= .006	
Relay Test Results for: CLOSING ANGLE		
LAGGING ANGLE	IDEAL	RANGE
14.97	15.00	10.00 TO 20.00
		OK? PASS
LEADING ANGLE	IDEAL	RANGE
344.85	345.00	340.00 TO 350.00
		OK? PASS
Relay Test Results for: LVL LIMIT TEST		
PICKUP VOLTS	IDEAL	RANGE
109.450	110.000	106.700 TO 113.300
		OK? PASS
Relay Test Results for: UVL LIMIT TEST		
PICKUP VOLTS	IDEAL	RANGE
121.000	121.000	114.950 TO 127.050
		OK? PASS
Relay Test Results for: LVB LIMIT TEST		
PICKUP VOLTS	IDEAL	RANGE
109.450	110.000	106.700 TO 113.300
		OK? PASS
Relay Test Results for: UVB LIMIT TEST		
PICKUP VOLTS	IDEAL	RANGE
121.000	121.000	117.370 TO 124.630
		OK? PASS
Relay Test Results for: DEAD LINE LIMIT		
PICKUP VOLTS	IDEAL	RANGE
49.500	50.000	48.500 TO 51.500
		OK? PASS
Relay Test Results for: DEAD BUS LIMIT		
PICKUP VOLTS	IDEAL	RANGE
49.500	50.000	48.500 TO 51.500
		OK? PASS
Relay Test Results for: UF LIMIT		
PICKUP HZ	IDEAL	RANGE
59.997	59.994	59.969 TO 60.019
		OK? PASS

Relay Test Results for: OF LIMITPICKUP HZ
60.003IDEAL
60.006RANGE
59.981 TO 60.131OK?
PASS

RTS Relay Test Results

Powered by:



Lib Routine: M-0359.FL_LIB	AF/AL: AL	Pass/Fail: PASS
Lib Version: 1.0	Test Date: 03/11/2018	
Relay Data:		
TESTED_BY: R.GERHARDT	DIVISION: FL-NORTH COASTAL	
SUBSTATION: CRPL-S4 604	TERMINAL: UNIT 4 syncloser M0359	
PRINT_CODE: 5F	PHASE_ZONE: ABC	
RELAY_MANF: BECKWITH	RELAY_TYPE: M-0359	
MODEL_STYLE: M-0359	IEEE_DEVICE:	
IL_IB:	SERIAL_NUMBER: NA	
FIRMWARE:	RELAY_ID: 5600884	
WO_NUMBER:	REASON_FOR_TEST: MAINTENANCE	
NERC_AUDITABLE:	NERC_SUBNUM:	
MAINT_INTERVAL:	PREVIOUS_TESTDATE:	
CURRENT_TESTDATE: 3/11/2018	NEXT_TESTDATE:	
TESTSET_CALDATE:	APPROVED_BY:	
Global Defines:		
Routine Notes:		
Relay Settings Used for Testing:		
TEST_VOLTS= 115	CLOSE_ANGLE= 15	DEAD_LINE= 50
DEAD_BUS= 50	LV_LIMIT= 110	UV_LIMIT= 121
NORM_FREQ= 60	FREQ_DIFF= .006	
Relay Test Results for: CLOSING ANGLE		
LAGGING ANGLE	IDEAL	RANGE
14.97	15.00	10.00 TO 20.00
		OK? PASS
LEADING ANGLE	IDEAL	RANGE
344.85	345.00	340.00 TO 350.00
		OK? PASS
Relay Test Results for: LVL LIMIT TEST		
PICKUP VOLTS	IDEAL	RANGE
109.450	110.000	106.700 TO 113.300
		OK? PASS
Relay Test Results for: UVL LIMIT TEST		
PICKUP VOLTS	IDEAL	RANGE
121.000	121.000	114.950 TO 127.050
		OK? PASS
Relay Test Results for: LVB LIMIT TEST		
PICKUP VOLTS	IDEAL	RANGE
109.450	110.000	106.700 TO 113.300
		OK? PASS
Relay Test Results for: UVB LIMIT TEST		
PICKUP VOLTS	IDEAL	RANGE
121.000	121.000	117.370 TO 124.630
		OK? PASS
Relay Test Results for: DEAD LINE LIMIT		
PICKUP VOLTS	IDEAL	RANGE
49.500	50.000	48.500 TO 51.500
		OK? PASS
Relay Test Results for: DEAD BUS LIMIT		
PICKUP VOLTS	IDEAL	RANGE
49.500	50.000	48.500 TO 51.500
		OK? PASS
Relay Test Results for: UF LIMIT		
PICKUP HZ	IDEAL	RANGE
59.997	59.994	59.969 TO 60.019
		OK? PASS

Relay Test Results for: OF LIMITPICKUP HZ
60.003IDEAL
60.006

59.981

RANGE
TO 60.131OK?
PASS

20210001-El Staff Hearing Exhibits 00117

STATION: CRYSTAL RIVER PLANT		DEF's Response to Staff Rog 5	
TYPE: Generator Protection		JUSTIFICATION: CHANGE	
VOLTAGE (KV): 230		THOR/PROJECT# 2836S2	
DESIGNATION: UNIT#4 MAN SYNC/VOLT CHECK		Equipment# 5600884	
BREAKER(S): 3233, 3234		SHEET # 1 OF 1	
DEVICE: 25/27		RELAY MODEL M-0359	PHASE A, 3Ph or Other B C
CATEGORY: ONLY		PRINT CODE 5-F/43-C	
ACTIVE SETTING GROUP		LAST CALC BY: PARRIS VAN SMITH	
RELAY SCHEME		LAST CALC DATE: 3/9/2002	
S/N: 1711		CUSTOMER OWNED (Y/N):	
FIRMWARE VER No. or FID No.			

SETTING NAME	SETTING	SETTING	COMMENTS
PTR (1)	1200	AF AL	
UPPER VOLTAGE LIMIT	121	120.75 120.75	251KV (+5%)
LOWER VOLTAGE LIMIT	110	112.7 109.45	223KV (-5%)
DELTA V LIMIT	2	2.07 2.07	DELTA 4.2KV (Ph-Ph)
DEAD LINE LIMIT	50	50.21 50.17	USED (Black Start)
DEAD BUS LIMIT	50	N/A N/A	NOT USED
PHASE ANGLE LIMIT	15	15.14 15.14	
DELTA F LIMIT	0.06	0.062 0.062	

***** All changes to this section must be reviewed by Transmission Engineering ***** (Applicable only for relay replacement or new installation performed by Construction or Maintenance). New relay installation verification check list.	
☒ Relay inputs in use verified ☒ Relay outputs in use verified ☒ Relay targets verified ☐ Relay test software (RTS) or ☒ Manual ☒ Final after testing - Setting file in relay is verified Test Personnel: <i>Michael D. Benson</i>	
☒ Functional Testing Complete This relay has been tested and commissioned according to Duke Energy Procedures: Protective Relaying for Technicians, Chapter 25, Appendix B, "Minimum Requirements for Acceptance on Capital Projects". Test Personnel: <i>Michael D. Benson</i> Date: <i>04/29/2020</i>	
ENG COMMENTS: (HISTORIC)	Supervises Manual Closes.
ENG REMARKS: (CURRENT)	Issuing setting sheet due to relocation of relay from Panel 5-F in the 230 kV control house to new 230/500 kV CEE, Panel 43-C. No change of settings.
FIELD COMMENTS:	
Underfrequency Set Points 1=59.6+10cy, 2=59.4+10cy, 3=59.2+10cy, 4=59.0+10cy, 5=58.7+10cy, 6=58.4+10cy, 7=58.2+10cy, 8=59.6+15sec, 9=59.6+22sec, NT=No Trip	
***** RELAY TECHNICIAN CHECK LIST ***** 1). Markup changes to electromechanical relays on setting sheet 5). Verify all CT ratios related to this setting sheet 2). Revise setting file name above to As-Left with corresponding Date. 6). Add Electronic Signature 3). Record S/N & Firmware Version for IED rly's and FID for all SEL rly's 7). E-mail Setting Sheet and As-Left Setting File To: relaysettings@duke-energy.com and to the RCE 4). Verify complete relay model number & record if not shown	
PREPARED BY: JAMES FERRELL 407-739-4375	PEER REVIEW BY: MARK WAGNER
Digitally signed by James Ferrell Date: 2020.01.30 15:18:37 -05'00'	Digitally signed by MARK WAGNER Date: 2020.02.06 13:20:08 -05'00'
Preparer's Signature	Reviewer's Signature
Relay Tech Signature <i>Michael D. Benson</i>	

20210001-DEF-000140

RTS Relay Test Results

Test Date:		AF/AL: AF		Pass/Fail: PASS	
Relay Data:					
Company_Name:	P.E. Florida	Area:	OC/WW Relay		
Substation:	CRPL U4	Terminal:	Unit 4		
Generator					
Panel_Bkr:	5-F (230 House)	Phase_Zone:	Synch Check		
Relay_Manf:	Beckwith	Relay_Type:	Syncrocloser		
Model_Style:	M-0359	Serial_Number:	NA		
IL_IB:		Test_Date:	11/19/2011		
Tested_By:	D. McCutchen	Reason_For_Test:	MJR. MAINT.		
PassPort_EQ_Number:	N/A	PassPort_WO_Number:			
Aspen_Relay_Group_Number:	5600884				
Routine Notes:					
<undefined>					
Relay Settings Used for Testing:					
RATED_AC=	120	TEST_VOLTS=	115	Lower_V_Limit=	110
Upper_V_Limit=	121	Delta_V_Limit=	2	Phase_Angle=	15
Delta_F_Limit=	0.05	Dead_Line_Limit=	50	Dead_Bus_Limit=	50
NOM_FREQ=	60				
<u>SENSE-Upper Voltage Limit Bus TEST</u>					
SENSE-UPPER VOLTAGE LIMIT BUS TEST					
	DROPOUT VOLTS	IDEAL		RANGE	OK?
	120.879	121.000	117.370	TO 124.630	PASS
<u>SENSE-Upper Voltage Limit Line TEST</u>					
SENSE-UPPER VOLTAGE LIMIT LINE TEST					
	DROPOUT VOLTS	IDEAL		RANGE	OK?
	120.879	121.000	117.370	TO 124.630	PASS
<u>SENSE-Lower Voltage Limit Bus TEST</u>					
SENSE-LOWER VOLTAGE LIMIT BUS TEST					
	DROPOUT VOLTS	IDEAL		RANGE	OK?
	109.890	110.000	106.700	TO 113.300	PASS
<u>SENSE-Lower Voltage Limit Line TEST</u>					
SENSE-LOWER VOLTAGE LIMIT LINE TEST					
	DROPOUT VOLTS	IDEAL		RANGE	OK?
	109.890	110.000	106.700	TO 113.300	PASS
<u>SENSE-Phase Angle Limit TEST</u>					
SENSE-PHASE ANGLE LIMIT TEST					
	LAGGING ANGLE	IDEAL		RANGE	OK?
	15.00	15.00	13.00	TO 17.00	PASS
	LEADING ANGLE	IDEAL		RANGE	OK?
	344.50	345.00	343.00	TO 347.00	PASS

SENSE-Delta V TEST

Q13a

SENSE-DELTA V TEST

DELTA V PICKUP

SET POINT

RANGE

OK?

2.05

2.00

1.65 TO 2.35

PASS

SENSE-Dead Line Limit TEST

SENSE-DEAD LINE LIMIT TEST

PICKUP

VOLTS
49.750IDEAL
50.000

47.500

RANGE

TO 52.500

OK?
PASS**SENSE-Dead Bus Limit Test**

SENSE-DEAD BUS LIMIT TEST

PICKUP

VOLTS
49.750IDEAL
50.000

47.500

RANGE

TO 52.500

OK?
PASS**SENSE-Delta Frequency NO-OP**

SENSE-DELTA FREQUENCY NO-OP

APPLIED
FREQUENCY
59.94REFERENCE
FREQUENCY
60.00OPERATION
EXPECTED?
NOOPERATION
OCCUR?
NOOK?
PASS**SENSE-Delta Frequency TEST**

SENSE-DELTA FREQUENCY TEST

PICKUP HZ

59.940

59.920

RANGE

TO 59.980

OK?
PASS

DROPOUT HZ

59.960

59.920

RANGE

TO 59.980

RTS Relay Test Results

Test Date:		AF/AL: AL		Pass/Fail: PASS	
Relay Data:					
Company_Name:	P.E. Florida	Area:	OC/WW Relay		
Substation:	CRPL U4	Terminal:	Unit 4		
Generator					
Panel_Bkr:	5-F (230 House)	Phase_Zone:	Synch Check		
Relay_Manf:	Beckwith	Relay_Type:	Syncrocloser		
Model_Style:	M-0359	Serial_Number:	NA		
IL_IB:		Test_Date:	11/19/2011		
Tested_By:	D. McCutchen	Reason_For_Test:	MJR. MAINT.		
PassPort_EQ_Number:	N/A	PassPort_WO_Number:			
Aspen_Relay_Group_Number:	5600884				
Routine Notes:					
<undefined>					
Relay Settings Used for Testing:					
RATED_AC=	120	TEST_VOLTS=	115	Lower_V_Limit=	110
Upper_V_Limit=	121	Delta_V_Limit=	2	Phase_Angle=	15
Delta_F_Limit=	0.05	Dead_Line_Limit=	50	Dead_Bus_Limit=	50
NOM_FREQ=	60				
<u>SENSE-Upper Voltage Limit Bus TEST</u>					
SENSE-UPPER VOLTAGE LIMIT BUS TEST					
	DROPOUT VOLTS	IDEAL		RANGE	OK?
	120.879	121.000	117.370	TO 124.630	PASS
<u>SENSE-Upper Voltage Limit Line TEST</u>					
SENSE-UPPER VOLTAGE LIMIT LINE TEST					
	DROPOUT VOLTS	IDEAL		RANGE	OK?
	120.879	121.000	117.370	TO 124.630	PASS
<u>SENSE-Lower Voltage Limit Bus TEST</u>					
SENSE-LOWER VOLTAGE LIMIT BUS TEST					
	DROPOUT VOLTS	IDEAL		RANGE	OK?
	109.890	110.000	106.700	TO 113.300	PASS
<u>SENSE-Lower Voltage Limit Line TEST</u>					
SENSE-LOWER VOLTAGE LIMIT LINE TEST					
	DROPOUT VOLTS	IDEAL		RANGE	OK?
	109.890	110.000	106.700	TO 113.300	PASS
<u>SENSE-Phase Angle Limit TEST</u>					
SENSE-PHASE ANGLE LIMIT TEST					
	LAGGING ANGLE	IDEAL		RANGE	OK?
	15.00	15.00	13.00	TO 17.00	PASS
	LEADING ANGLE	IDEAL		RANGE	OK?
	344.50	345.00	343.00	TO 347.00	PASS

SENSE-Delta V TEST

SENSE-DELTA V TEST

DELTA V PICKUP

SET POINT

RANGE

OK?

2.05

2.00

1.65 TO 2.35

PASS

SENSE-Dead Line Limit TEST

SENSE-DEAD LINE LIMIT TEST

PICKUP

VOLTS
49.750IDEAL
50.000

47.500

RANGE
TO 52.500OK?
PASS**SENSE-Dead Bus Limit Test**

SENSE-DEAD BUS LIMIT TEST

PICKUP

VOLTS
49.750IDEAL
50.000

47.500

RANGE
TO 52.500OK?
PASS**SENSE-Delta Frequency NO-OP**

SENSE-DELTA FREQUENCY NO-OP

APPLIED
FREQUENCY
59.94REFERENCE
FREQUENCY
60.00OPERATION
EXPECTED?
NOOPERATION
OCCUR?
NOOK?
PASS**SENSE-Delta Frequency TEST**

SENSE-DELTA FREQUENCY TEST

PICKUP HZ
59.940
DROPOUT HZ
59.960RANGE
59.920 TO 59.980
RANGE
59.920 TO 59.980OK?
PASS

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 6th day of October 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GARY P. DEAN, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory numbers 8 and 10, of STAFF'S FIFTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 8-14) in Docket No. 20210001-EI, and that the responses are true and correct based on his personal knowledge.

THE FOREGOING INSTRUMENT was sworn to and subscribed before me by means of
☐ physical presence or ☒ online (video) notarization by Gary Dean, who is personally known to me.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of October, 2021.



Gary P. Dean

Notary Public
State of Florida

My Commission Expires: 6/28/23

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 9th day of Oct, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared INGLE LEWTER, who is personally known to me, and has acknowledged before me that she provided the answer to interrogatory number 9, of STAFF'S FIFTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 8-14) in Docket No. 20210001-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of October, 2021.

Ingle Lewter
Ingle Lewter



Mecklenburg County, NC
The foregoing instrument was acknowledged before me on this 9th day of OCTOBER, 2021 by MARY INGLE LEWTER, who acknowledged to me that he or she willingly signed and executed the instrument for the purposes stated in it.
Raj Patel
Notary Public

Raj Patel

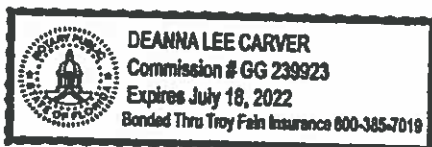
AFFIDAVIT

STATE OF FLORIDA

COUNTY OF CITRUS

I hereby certify that on this 16th day of Oct, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JOSEPH SIMPSON, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory numbers 11, 12, 13, and 14, of STAFF'S FIFTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 8-14) in Docket No. 20210001-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of October, 2021.



Joseph Simpson
Joseph Simpson
Deanna Lee Carver
Notary Public
State of Florida

My Commission Expires: July 18, 2022

TECO's Response to Staff's Second Set of Interrogatories, No. 4.

**TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
STAFF'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 4
BATES PAGE: 1
FILED: OCTOBER 12, 2021**

4. The following question is related to fuel price forecast underlying Tampa Electric Company's (TECO or Company) Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery for the period January through December 2022. Staff observes that both spot and forward pricing (short and medium term) have increased considerably since this past August (presumably near or when the data used to develop TECO's projected 2022 fuel cost was sourced). Does the Company still believe the forward natural gas pricing data underlying (embedded in) its current cost projection of 2022 remains adequate for setting the 2022 fuel cost recovery factor?
 - A. Tampa Electric does not plan to re-file the company's 2022 projection with updated pricing data. As indicated in the notice filed by Tampa Electric in this docket on October 8, 2021, the company now projects an under-recovery in excess of 10 percent is likely to occur absent a modification to the company's 2022 cost recovery factors filed on September 3, 2021. Given current natural gas price volatility, the company will defer a decision regarding whether to file for a mid-course correction to its 2022 fuel cost recovery factors and will provide a further notice by December 1, 2021.

AFFIDAVIT

STATE OF Florida)

COUNTY OF Hillsborough)

I hereby certify that on this day 7th of October, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared M. Ashley Sizemore, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatories in

Staff's 1st set, (Nos. 1 - 3),

Staff's 2nd set, (Nos. 4),

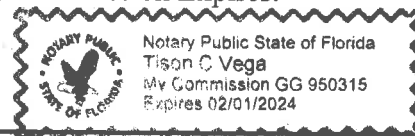
in Docket No. 20210001-EI, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this day 7th of October, 2021.

M. Ashley Sizemore
Witness

Tison C. Vega
Notary Public
State of Florida, at Large

My Commission Expires:



FPL's Response to Staff's Sixth Set of Interrogatories, No. 15.

**Florida Power & Light Company
Docket No. 20210001-EI
Staff's 6th Set of Interrogatories
Interrogatory No. 15
Page 1 of 1**

QUESTION:

The following question is related to Florida Power & Light's (FPL or Company) North Florida Resiliency Connection (NFRC) and how it may potentially impact fuel and or capacity costs contained in the Company's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery for the period January through December 2022. Please discuss what affects, if any, the NFRC may have on the requested rates in this docket and/or potentially other related matters during this year's clause cycle.

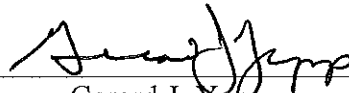
RESPONSE:

The NFRC will facilitate the joint dispatch of the FPL and Gulf systems and drive the potential for fuel cost savings (lower fuel rates) by providing the ability to dispatch the most efficient (or least cost) generation to serve the combined load.

DECLARATION

I sponsored the answer to Interrogatory No. 15 from **STAFF'S SIXTH SET OF INTERROGATORIES (NO. 15)** to Florida Power & Light Company in Docket No. 20210001-EI. The responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and the interrogatory answers identified above, and that the facts stated therein are true.



Gerard J. Yupp

Date: 10/12/21

FPL's Response to Staff's Seventh Set of Interrogatories, No. 16.

**Florida Power & Light Company
Docket No. 20210001-EI
Staff's 7th Set of Interrogatories
Interrogatory No. 16
Page 1 of 1**

QUESTION:

Please refer to Florida Power & Light's (FPL or Company) amended 2022 Risk Management Plan (RMP). Florida Public Service Commission Order No. PSC-08-0667-PAA-EI, Attachment B specifies 15 components to be addressed in a utility's Risk Management Plan. The Company appears to have addressed Item Nos. 1, 3-9, 13, and 14. Please address Items 2, 10-12, and 15 by discussing the component topic or by noting the specific component is moot or unnecessary given a potential future moratorium with respect to financial hedging.

RESPONSE:

FPL confirms that Item Nos. 2 and 15 were excluded because they both are hedging-related and, therefore, are not necessary because FPL's updated 2022 Risk Management Plan excludes all financial hedging activity. The updated 2022 Risk Management Plan reflects the hedging moratorium to which FPL and co-signatories agreed in the proposed rate settlement agreement submitted in Docket 20210015-EI.

Item Nos. 10-12 are also excluded as unnecessary. As detailed in Exhibit 1, Hedging Order Clarification Guidelines, Section I(a), in Order No. PSC-08-0667-PAA-EI, dated October 8, 2008, items numbered 10-12 are specifically excluded from the list of components from Exhibit TFB-4 (ref. Order No. PSC-02-1484-FOF-EI) that should be included in each IOU's annual Risk Management Plan. Accordingly, FPL's updated 2022 Risk Management Plan does not include sections to address those items.

DEF's Response to OPC's First Request to Produce Documents, Nos. 1, 3, 4.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost
Recovery Clause and Generating
Performance Incentive Factor

Docket No. 20210001-EI

Filed: April 9, 2021

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO CITIZENS'
FIRST REQUEST TO PRODUCE DOCUMENTS (NOS. 1-4)**

Duke Energy Florida, LLC ("DEF"), responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") First Request to Produce Documents (Nos. 1-4), as follows:

DOCUMENTS REQUESTED

1. Please provide the documents identified in Citizens' Interrogatory No. 2.

Response:

Please see the attached documents bearing bates numbers 20210001-DEF-000001.

2. Please provide the documents identified in Citizens' Interrogatory No. 4.

Response:

Please see the attached documents bearing bates number bearing bates numbers 20210001-DEF-000002 through 20210001-DEF-000046.

The attachments are confidential: redacted versions are attached hereto and unredacted copies have been submitted with the Florida Public Service Commission along with DEF's Notice of Intent to Request Confidential Classification dated April 7, 2021.

3. Please provide the documents identified in Citizens' Interrogatory No. 6.

Response:

Please see the attached documents bearing bates numbers 20210001-DEF-000047.

4. Please provide the documents identified in Citizens' Interrogatory No. 8.

Response:

Please see the attached documents bearing bates numbers 20210001-DEF-000048 through 20210001-DEF-000056.

DUKE ENERGY FLORIDA
Bartow Replacement Power Cost (01/01/21 - 01/31/21)

Date	Fuel	Purchased Power	Total Cost
1-Jan-21	\$19,217	\$ -	\$19,217
2-Jan-21	\$11,137	\$ -	\$11,137
3-Jan-21	\$10,118	\$ -	\$10,118
4-Jan-21	\$744	\$ -	\$744
5-Jan-21	\$13,253	\$ 13,902	\$27,155
6-Jan-21	\$88,399	\$ (2)	\$88,397
7-Jan-21	\$97,941	\$ -	\$97,941
8-Jan-21	\$76,861	\$ -	\$76,861
9-Jan-21	\$80,556	\$ -	\$80,556
10-Jan-21	\$101,427	\$ 56	\$101,483
11-Jan-21	\$18,907	\$ -	\$18,907
12-Jan-21	\$16,824	\$ -	\$16,824
13-Jan-21	\$9,086	\$ -	\$9,086
14-Jan-21	\$182	\$ -	\$182
15-Jan-21	\$1,467	\$ -	\$1,467
16-Jan-21	-\$532	\$ -	-\$532
17-Jan-21	\$10,744	\$ -	\$10,744
18-Jan-21	-\$5,136	\$ -	-\$5,136
19-Jan-21	\$2,101	\$ -	\$2,101
20-Jan-21	-\$3,540	\$ -	-\$3,540
21-Jan-21	\$82	\$ -	\$82
22-Jan-21	\$4,747	\$ -	\$4,747
23-Jan-21	\$4,615	\$ -	\$4,615
24-Jan-21	\$4,619	\$ -	\$4,619
25-Jan-21	\$4,786	\$ -	\$4,786
26-Jan-21	\$4,818	\$ -	\$4,818
27-Jan-21	\$4,817	\$ -	\$4,817
28-Jan-21	\$3,797	\$ -	\$3,797
29-Jan-21	\$980	\$ -	\$980
30-Jan-21	\$7,185	\$ -	\$7,185
31-Jan-21	\$3,781	\$ -	\$3,781
Total	\$593,986	\$13,956	\$607,942

Month	System Replacement Power	Monthly Jurisdictional Factor	Retail Replacement Power
Jan-21	\$607,942	100.00%	\$607,942

Duke Energy Florida
20210001-EI
DEF's Response to OPC POD 1 (1-4)
Q2

Documents bearing bates numbers
20210001-DEF-000002
through
20210001-DEF-000046
are confidential in their entirety.

DUKE ENERGY FLORIDA
Crystal River Unit 4 (CR4) Replacement Power Cost (01/01/21 - 01/31/21)

Date	Fuel	Purchased Power	Total Cost
1-Jan-21	\$0	\$ -	\$0
2-Jan-21	\$0	\$ -	\$0
3-Jan-21	\$0	\$ -	\$0
4-Jan-21	\$0	\$ -	\$0
5-Jan-21	\$0	\$ -	\$0
6-Jan-21	\$50,217	\$ 817	\$51,034
7-Jan-21	\$47,062	\$ -	\$47,062
8-Jan-21	\$35,680	\$ -	\$35,680
9-Jan-21	\$144,608	\$ 42,579	\$187,187
10-Jan-21	\$89,456	\$ (40,824)	\$48,632
11-Jan-21	\$26,782	\$ -	\$26,782
12-Jan-21	-\$9,103	\$ -	-\$9,103
13-Jan-21	\$58,126	\$ -	\$58,126
14-Jan-21	\$45,079	\$ -	\$45,079
15-Jan-21	\$38,805	\$ -	\$38,805
16-Jan-21	\$38,391	\$ -	\$38,391
17-Jan-21	\$50,625	\$ -	\$50,625
18-Jan-21	\$47,990	\$ -	\$47,990
19-Jan-21	\$60,914	\$ -	\$60,914
20-Jan-21	\$32,920	\$ -	\$32,920
21-Jan-21	\$4,298	\$ -	\$4,298
22-Jan-21	-\$8,969	\$ -	-\$8,969
23-Jan-21	-\$8,453	\$ -	-\$8,453
24-Jan-21	-\$3,196	\$ -	-\$3,196
25-Jan-21	\$14,613	\$ -	\$14,613
26-Jan-21	\$11,623	\$ -	\$11,623
27-Jan-21	\$21,738	\$ -	\$21,738
28-Jan-21	\$29,859	\$ -	\$29,859
29-Jan-21	\$44,947	\$ -	\$44,947
30-Jan-21	\$27,919	\$ -	\$27,919
31-Jan-21	\$24,572	\$ -	\$24,572
Total	\$916,503	\$2,571	\$919,074

Month	System Replacement Power	Monthly Jurisdictional Factor	Retail Replacement Power
Jan-21	\$919,074	100.00%	\$919,074



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

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		
<i>A4B5C09 – Change-related documents not developed or revised</i>		
Corrective Action Describe specific actions taken or required.	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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 <u>SHALL</u> 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):	<i>A3B3C04 – LTA review based on assumption that process will not change</i> <i>A4B2C04 – Resources not provided to assure adequate training was provided/ maintained</i> <i>A3B3C06 – Individual underestimated the problem by using past events as basis</i> <i>A6B2C01 – Practice or “hands-on” experience LTA</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> 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):	<i>A5B1C01 – Format deficiencies</i> <i>A5B2C08 – Incomplete/situation not covered</i> <i>A5B2C01 – Limit inaccuracies</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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 <u>SHALL</u> 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



RMA 21184 DUKE
ENERGY EVALUATION

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



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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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

DEF's Response to OPC's First Set of Interrogatories, Nos. 1-8.

INTERROGATORIES

Please reference the February 26, 2021 GPIF Actual Unit Performance data schedules for January 2021 in responding to Interrogatories 1-8:

1. On page 1 of 14 (Bartow CC), please state if the EAF % of 82.10 for the month of January 2021 is attributable fully or in part to the seven Full Forced Outage (FFO) or Partial Forced Outage (PFO) events with hours totaling 497.85, 139.63, 0.42, 161.23, 0.62, 113.47 and 497.85 for 195 MW, 195 MW, 195 MW, 195 MW, 195 MW, 389 MW and 63 MW, respectively, beginning on dates January 11, 1, 11, 1, 16, 5, and 11, 2021, respectively as shown on page 8 of 14.
2. If the answer to Interrogatory No. 1 is yes, please identify the amount of replacement power cost attributable to the unit unavailability below an EAF of 100%. Please also identify the workpapers calculating such replacement power costs.
3. Please state whether Duke Energy Florida, LLC intends to seek, or has already sought, recovery of the replacement power costs identified in response to Interrogatory No. 2.
4. Please identify all documents related to any and all root cause analyses (or the functional equivalent, regardless of title), including drafts and related commentary correspondence, involving the forced outages occurring at Bartow CC in January 2021.
5. On page 2 of 14 (Crystal River 4), please state if the EAF % of 0.00 for the month of January 2021 is attributable fully or in part to the Full Forced Outage (FFO) hours totaling 744 for 712 MW, beginning January 1, 2021 as shown on page 9 of 14.
6. If the answer to Interrogatory No. 5 is yes, please identify the amount of replacement power cost attributable to the unit unavailability below an EAF of 100%. Please also identify the workpapers calculating such replacement power costs.
7. Please state whether Duke Energy Florida, LLC intends to seek, or has already sought, recovery of the replacement power costs identified in response to Interrogatory No. 6.

8. Please identify all documents related to any and all root cause analyses (or the functional equivalent, regardless of title), including drafts and related commentary correspondence, involving the forced outages occurring at Crystal River 4 in January 2021.

Respectfully Submitted,

Richard Gentry
Public Counsel

s/Anastacia Pirrello
Anastacia Pirrello
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street
Room 812
Tallahassee, FL 32399-1400

Attorneys for the Citizens
of the State of Florida

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF _____)

I hereby certify that on this _____ day of _____, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared _____, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) _____ from in CITIZENS' FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC COMPANY (NOS. 1-8 in Docket No. 20210001, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this _____ day of _____, 2021.

Notary Public
State of Florida, at Large

My Commission Expires:

DEF's Response to OPC's Second Request to Produce Documents, No. 5-6.

(Including attachment to No. 5)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost
Recovery Clause and Generating
Performance Incentive Factor

Docket No. 20210001-EI

Filed: May 28, 2021

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO CITIZENS'
SECOND REQUEST TO PRODUCE DOCUMENTS (NOS. 5-8)**

Duke Energy Florida, LLC ("DEF"), responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Second Request to Produce Documents (Nos. 5-8), as follows:

DOCUMENTS REQUESTED

5. Please provide the documents identified in Citizens' Interrogatory No. 12.

Response:

Please see the attached document bearing bates number 20210001-DEF-000057.

6. Please provide the documents identified in Citizens' Interrogatory No. 14.

Response:

Please see the documents provided in DEF's response to OPC POD 1, question 2, bearing bates numbers Please see the attached documents bearing bates number bearing bates numbers 20210001-DEF-000002 through 20210001-DEF-000046.

7. Please provide the documents identified in Citizens' Interrogatory No. 16.

Response:

There are no documents to submit for this POD.

8. Please provide the documents identified in Citizens' Interrogatory No. 18.

Response:

There are no documents responsive to this request. The Hines Power 3 Block outage was a planned outage.

DUKE ENERGY FLORIDA
Bartow Replacement Power Cost (02/01/21 - 02/28/21)

Date	Fuel	Purchased Power	Total Cost
1-Feb-21	\$ (2,660)	\$ (19)	\$ (2,679)
2-Feb-21	\$ 1,129	\$ 2	\$ 1,131
3-Feb-21	\$ (14,596)	\$ 39,889	\$ 25,293
4-Feb-21	\$ 10,498	\$ 29,490	\$ 39,989
5-Feb-21	\$ 154	\$ -	\$ 154
6-Feb-21	\$ (1,356)	\$ -	\$ (1,356)
7-Feb-21	\$ (1,221)	\$ -	\$ (1,221)
8-Feb-21	\$ 1,078	\$ -	\$ 1,078
9-Feb-21	\$ 46,916	\$ -	\$ 46,916
10-Feb-21	\$ 51,254	\$ -	\$ 51,254
11-Feb-21	\$ 45,960	\$ -	\$ 45,960
12-Feb-21	\$ 23,215	\$ -	\$ 23,215
13-Feb-21	\$ 17,551	\$ -	\$ 17,551
14-Feb-21	\$ 63,530	\$ 13,841	\$ 77,371
15-Feb-21	\$ 74,022	\$ 200	\$ 74,222
16-Feb-21	\$ 48,118	\$ -	\$ 48,118
17-Feb-21	\$ 76,175	\$ (14,165)	\$ 62,010
18-Feb-21	\$ 153,108	\$ (13,538)	\$ 139,570
19-Feb-21	\$ 62,266	\$ -	\$ 62,266
20-Feb-21	\$ 54,148	\$ -	\$ 54,148
21-Feb-21	\$ 119	\$ -	\$ 119
22-Feb-21	\$ 131,626	\$ -	\$ 131,626
23-Feb-21	\$ 111,989	\$ -	\$ 111,989
24-Feb-21	\$ 87,604	\$ -	\$ 87,604
25-Feb-21	\$ 95,102	\$ -	\$ 95,102
26-Feb-21	\$ 101,161	\$ -	\$ 101,161
27-Feb-21	\$ 112,320	\$ 175	\$ 112,496
28-Feb-21	\$ 41,653	\$ (28,565)	\$ 13,088
Total	\$ 1,390,864	\$ 27,310	\$ 1,418,174

Month	System Replacement Power	Monthly Jurisdictional Factor	Retail Replacement Power
Feb-21	\$1,418,174	99.46%	\$1,410,516

DEF's Response to OPC's Third Set of Interrogatories, Nos. 11-18.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost
Recovery Clause and Generating
Performance Incentive Factor

Docket No. 20210001-EI

Filed: May 28, 2021

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
CITIZENS' THIRD SET OF INTERROGATORIES (NOS. 11-18)**

Duke Energy Florida, LLC ("DEF") responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Third Set of Interrogatories to DEF (Nos. 11-18) as follows:

INTERROGATORIES

Please reference the April 28, 2021 GPIF Actual Unit Performance Data Report for February 2021 (corrected) in responding to Interrogatories 11-18:

11. On page 1 of 14 (Bartow CC), please state if the EAF % of 75.31 for the month of February 2021 is attributable fully or in part to the Forced Maintenance Outage (FMO) event with hours totaling 142.85 for 339 MW, beginning on February 22, 2021 as shown on page 8 of 14.

Response:

To avoid a misinterpretation of terms, DEF is seeking to clarify any terms in this response. In the GPIF Manual, FMO stands for Full Maintenance Outage, and PO stands for planned outage. The EAF is partly due to the full maintenance outage that began on February 22. It is also attributable to the full forced outage (FFO) of the 4A combustion turbine generator. With the 4A combustion turbine not available, it cannot contribute steam to the steam turbine and thus the overall power block EAF is reduced.

12. If the answer to Interrogatory No. 11 is yes, please identify the amount of replacement power cost attributable to the unit unavailability below an EAF of 100%. Please also identify the workpapers calculating such replacement power costs.

Response:

The replacement power cost for the outages identified in response to Interrogatory No. 11, during the month of February 2021, is approximately \$1.4 million. To calculate the replacement power cost assuming Bartow CC had not experienced the outages, DEF ran a production cost simulation model beginning February 1, 2021 through February 28, 2021; this process is consistent with DEF's prior replacement power calculations. DEF ran this simulation model, applying the actual load conditions and replacement fuel costs, which produced the total system cost assuming Bartow CC was fully available. DEF then

compared the resulting “with Bartow CC” system cost to the system cost calculated based on actual unit loadings (i.e., without Bartow 2 CC). The difference between the “with Bartow CC” cost and the “without Bartow CC” cost represents the system replacement power costs during the Bartow CC Outage.

Please see the response to OPC’s Second Request for Production of Documents, question 5.

13. Please state whether Duke Energy Florida, LLC intends to seek, or has already sought, recovery of the replacement power costs identified in response to Interrogatory No. 11.

Response:

These replacement costs were not included in the 2021 projection filing and therefore are not included in the current fuel cost recovery factor. DEF intends to include the replacement power costs identified in DEF’s response to OPC’s Interrogatory No. 12 in its 2021 Actual/Estimated true-up calculation and seek recovery of those costs in its 2022 fuel factors.

14. Please identify all documents related to any and all root cause analyses (or the functional equivalent, regardless of title), including drafts and related commentary correspondence, involving the forced outage occurring at Bartow CC in February 2021.

Response:

Please see the documents provided in DEF’s Response to OPC POD 2, question 6, bearing bates numbers 20210001-DEF-000057 through 20210001-DEF-0000XX.

15. On page 6 of 14 (Hines Power Block 3), please state if the EAF % of 42.86 for the month of February 2021 is attributable fully or in part to the three Partial Outage (PO) events each with hours totaling 384 for 173.3 MW, 173.3 MW and 169.3 MW, all beginning on February 13, 2021 as shown on page 13 of 14.

Response:

The EAF of 42.86% is due to the spring planned outage (PO) discussed in response to Interrogatory 16, below.

16. If the answer to Interrogatory No. 15 is yes, please identify the amount of replacement power cost attributable to the unit unavailability below an EAF of 100%. Please also identify the workpapers calculating such replacement power costs.

Response:

On February 13th, 2021 at 00:00, the unit entered its spring planned outage (PO), where it remained through the remainder of February. DEF does not calculate “replacement power” costs for planned outages.

17. Please state whether Duke Energy Florida, LLC intends to seek, or has already sought, recovery of the replacement power costs identified in response to Interrogatory No. 15.

Response:

There are no replacement power costs. Please see the response to Interrogatory No. 16.

18. Please identify all documents related to any and all root cause analyses (or the functional equivalent, regardless of title), including drafts and related commentary correspondence, involving the partial outage occurring at Hines Power Block 3 in February 2021.

Response:

The Hines Power Block 3 outage was a planned outage; please see DEF's response to Interrogatory 16.

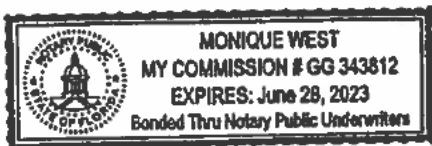
AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 7th day of May, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GARY P. DEAN, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory numbers 12, 13, 16, and 17 of CITIZENS' THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 11-18) in Docket No. 20210001-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of May, 2021.



[Signature]
Gary P. Dean

[Signature]
Notary Public
State of Florida, at Large

My Commission Expires: 6/28/2023

AFFIDAVIT

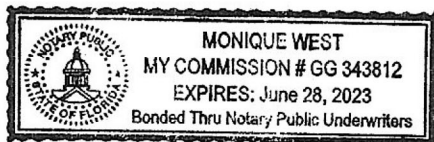
STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 19th day of May, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared INGLE LEWTER, who is personally known to me, and has acknowledged before me that she provided the answers to interrogatory number 15, of CITIZENS' THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 11-18) in Docket No. 20210001-EI, and that the responses are true and correct based on her personal knowledge.

THE FOREGOING INSTRUMENT was sworn to and subscribed before me by means of
☐ physical presence or ☒ online (video) notarization by Ingle Lewter, who is personally known to me.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19th day of May, 2021.



Ingle Lewter
Ingle Lewter
[Signature]
Notary Public
State of Florida

My Commission Expires: 6/28/2023

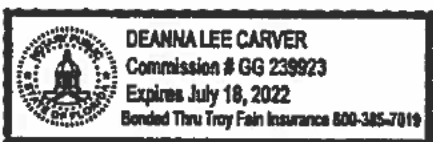
AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 19th day of MAY, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JEFFREY SWARTZ, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory numbers 11, 14, and 18, of CITIZENS' THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 11-18) in Docket No. 20210001-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19th day of May, 2021.



Jeffrey Swartz
Jeffrey Swartz

Deanna Lee Carver
Notary Public
State of Florida, at Large

My Commission Expires: July 18, 2022

DEF's Response to OPC's Fourth Set of Interrogatories, Nos. 19-32.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost
Recovery Clause and Generating
Performance Incentive Factor

Docket No. 20210001-EI

Filed: September 20, 2021

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
CITIZENS' FOURTH SET OF INTERROGATORIES (NOS. 19-32)**

Duke Energy Florida, LLC ("DEF") responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Fourth Set of Interrogatories to DEF (Nos. 19-32) as follows:

INTERROGATORIES

Please reference the July 28, 2021 GPIF Actual Unit Performance Data schedules for June 2021 in responding to interrogatories 19-25:

19. Describe in detail the nature of the planned outages for general gas turbine unit inspections and inspection at Hines Power Block 3 which began on February 13, 2021, occurring in units HEP 3A, HEP 3B, and HEP ST3 respectively.

Response

DEF restates and incorporates its objection to this interrogatory submitted on August 24, 2021.

20. Identify any deficiencies or needed repairs found during the inspections described in Interrogatory 19.

Response

DEF restates and incorporates its objection to this interrogatory submitted on August 24, 2021.

21. Describe the corrective actions necessary, if any, to remedy the deficiencies or needed repairs identified in Interrogatory 20.

Response

DEF restates and incorporates its objection to this interrogatory submitted on August 24, 2021.

22. On page 1 of 14 (Bartow CC), please state if the EAF % of 74.93 for the month of June 2021 is attributable fully or in part to the two Full Forced Outage (FFO) events with hours totaling 1,997.98 and 1,437.08 for 185 MW and 187 MW, respectively, beginning on January 11 and May 2, 2021 respectively, as shown on page 8 of 14.

Response

Bartow CC's EAF of 74.93% in June 2021 is partly attributed to the Full Forced Outage (FFO) occurring on May 2, for 1,437.08 hours and 187 MW. The FFO occurring on January 11, for 1,997.98 hours did not affect the unit's EAF performance in June.

23. If the answer to Interrogatory No. 22 is yes, please identify the amount of replacement power cost attributable to the unit unavailability below an EAF of 100%. Please also identify the workpapers calculating such replacement power costs.

Response

Bartow CC's EAF of 74.93% in June 2021 is also partly attributed to a Planned Outage on the 4D unit that began on June 18th. DEF does not calculate replacement power costs for planned outages.

The replacement power cost for Bartow during the month of June 2021 (excluding the Planned Outage that began on June 18th), is approximately \$1.9 million. To calculate the replacement power cost assuming Bartow CC had not experienced other outage events, DEF ran a production cost simulation model beginning June 1, 2021 through June 30, 2021; this process is consistent with DEF's prior replacement power calculations. DEF ran this simulation model, applying the actual load conditions and replacement fuel costs, which produced the total system cost assuming Bartow CC was fully available, with the exception of the Planned Outage on 4D. DEF then compared the resulting "with Bartow CC" system cost to the system cost calculated based on actual unit loadings (i.e., without Bartow CC). The difference between the "with Bartow CC" cost and the "without Bartow CC" cost represents the system replacement power costs during the Bartow CC outages.

Please see DEF's response to OPC's Third Request for Production of Documents, question 11.

24. Please state whether Duke Energy Florida, LLC intends to seek, or has already sought, recovery of the replacement power costs identified in response to Interrogatory No. 23.

Response

These replacement costs were not included in the 2021 projection filing and therefore are not included in the current fuel cost recovery factor. DEF included the replacement power costs identified in DEF's response to OPC's Interrogatory No. 23 in its 2021 Actual/Estimated true-up calculation and plans to seek recovery of those costs in its 2022 fuel factors.

25. Please identify all documents related to any and all root cause analyses (or the functional equivalent, regardless of title), including drafts and related commentary correspondence, involving the forced outages occurring at Bartow CC in June 2021.

Response

DEF restates and incorporates its objection to this interrogatory submitted on August 24, 2021. Subject to and without waiving its objection to this interrogatory, DEF does not have any documents responsive to this request at this time.

Please reference the June 28, 2021 GPIF Actual Unit Performance Data schedules for May 2021 in responding to interrogatories 26-32:

26. On page 1 of 14 (Bartow CC), please state if the EAF % of 78.63 for the month of May 2021 is attributable fully or in part to the six Full Forced Outage (FFO) and one Partial Forced Outage (PFO) events with hours totaling 5.38, 61.48, 10.02, 113.42, 15.25, 2.00 and 717.08 for 183 MW, 183 MW, 183 MW, 183 MW, 183 MW, 186 MW and 13 MW respectively, beginning on dates May 1, 1, 4, 5, 9, 29 and 2, 2021 respectively as shown on page 8 of 14.

Response

Bartow CC's EAF of 78.63% in May 2021 is partly attributed to the six Full Forced Outages (FFO) occurring on May 1, 4, 5, 9, 29, and one Partial Forced Outage (PFO) occurring on May 2.

27. If the answer to Interrogatory No. 26 is yes, please identify the amount of replacement power cost attributable to the unit unavailability below an EAF of 100%. Please also identify the workpapers calculating such replacement power costs.

Response

The replacement power cost for this outage, during the month of May 2021, is approximately \$2.2 million. To calculate the replacement power cost assuming Bartow CC had not experienced the outage, DEF ran a production cost simulation model beginning May 1, 2021 through May 31, 2021; this process is consistent with DEF's prior replacement power calculations. DEF ran this simulation model, applying the actual load conditions and replacement fuel costs, which produced the total system cost assuming Bartow CC was fully available. DEF then compared the resulting "with Bartow CC" system cost to the system cost calculated based on actual unit loadings (i.e., without Bartow CC). The difference between the "with Bartow CC" cost and the "without Bartow CC" cost represents the system replacement power costs during the Bartow CC Outage.

Please see DEF's response to OPC's Third Request for Production of Documents, question 13.

28. Please state whether Duke Energy Florida, LLC intends to seek, or has already sought, recovery of the replacement power costs identified in response to Interrogatory No. 27.

Response

These replacement costs were not included in the 2021 projection filing and therefore are not included in the current fuel cost recovery factor. DEF included the replacement power costs identified in DEF's response to OPC's Interrogatory No. 27 in its 2021 Actual/Estimated true-up calculation and plans to seek recovery of those costs in its 2022 fuel factors.

29. Please identify all documents related to any and all root cause analyses (or the functional equivalent, regardless of title), including drafts and related commentary correspondence, involving the forced outages occurring at Bartow CC in May 2021.

Response

DEF restates and incorporates its objection to this interrogatory submitted on August 24, 2021. Subject to and without waiving its objection to this interrogatory, please see DEF's response to OPC's Third Request for Production of Documents, question 14.

30. Describe in detail the nature of the planned outages for general gas turbine unit inspections at Hines Power Block 1 which began on April 10, 2021, occurring in units HEP 1A, HEP 1B, and HEP ST1 respectively.

Response

DEF restates and incorporates its objection to this interrogatory submitted on August 24, 2021.

31. Identify any deficiencies or needed repairs found during the inspections described in Interrogatory 30.

Response

DEF restates and incorporates its objection to this interrogatory submitted on August 24, 2021.

32. Describe the corrective actions necessary, if any, to remedy the deficiencies or needed repairs identified in Interrogatory 31.

Response

DEF restates and incorporates its objection to this interrogatory submitted on August 24, 2021.

AFFIDAVIT

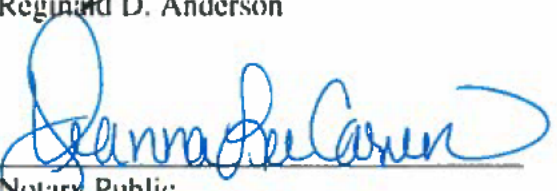
STATE OF FLORIDA

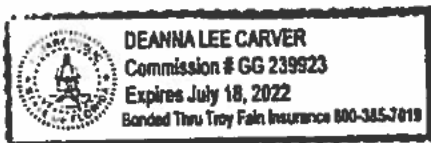
COUNTY OF PINELLAS

I hereby certify that on this 30th day of Aug, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared REGINALD D. ANDERSON, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory numbers 19, 20, 21, 22, 25, 26, 29, 30, 31, and 32 of CITIZENS' FOURTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 19-32) in Docket No. 20210001-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of August, 2021.


Reginald D. Anderson


Notary Public
State of Florida, at Large



My Commission Expires July 18, 2022

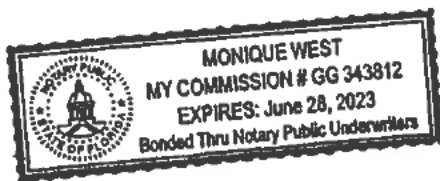
AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 24th day of August, 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GARY P. DEAN, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory numbers 23, 24, 27, and 28 of CITIZENS' FOURTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 19-32) in Docket No. 20210001-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24th day of August, 2021.



[Signature]
Gary P. Dean

[Signature]
Notary Public
State of Florida, at Large

My Commission Expires: 6/28/2023

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FPUC Responses to OPC's First Set of Interrogatories,

Nos. 1-5.

(Including attachments)

(Revised responses to Nos. 1-2)

Interrogatory No. 1

INTERROGATORIES

For the following questions please refer to pages 3-4 of Mr. Mark Cutshaw's 2022 Projection Testimony where he briefly discusses legal and consultant fees that are included in the fuel clause.

1. Please provide the amount(s) included in the 2021 fuel factor(s) for the consulting fees.

Company Response:

Please see Excel file Attachment OPC Rog 1-2.

Respondent: Curtis Young

Interrogatory No. 2

2. Please provided the amount(s) included in the 2021 fuel factor(s) for legal services fees.

Company Response:

Please see Excel file Attachment OPC Rog 1-2 for Gunster, Yoakley and Stewart and Locke Lord LLP.

Respondent: Curtis Young

Interrogatory No. 3

3. For any and all project costs and related consultant fees included in the 2021 fuel factor(s), please provide a description for each of the project(s), the name of the consultant(s) working on the project(s) by project, and the amount of time the consultant(s) have spent on each of the project(s) by project by year included in the fuel factor(s) (i.e. 2020, 2021, and 2022).

Company Response:

2020:

Christensen Associates Energy Consulting \$4,477.00 consisting of 12-15 hours

Charges included work on the new and amended PPA's with FPL for both the NE FL and NW FL divisions.

Pierpont & McLelland, LLC: \$17,933.59 consisting of 100-120 hours

Charges included work to help assist with the new and amended PPA's (\$2,647.63) and work towards the development of the contracts and agreement related to the proposed Amelia Island Energy CHP (\$15,285.96).

Sterling Energy, LLC: \$74,600 consisting of 575-590 hours

Charges included work to assist with the development, design and related agreements necessary for the Amelia Island Energy CHP.

Barry Kennedy: \$0.00

2021 YTD:

Christensen Associates Energy Consulting: \$8,048 consisting of 20-25 hours

Charges included work on the PPA's with FPL for both the NE FL and NW FL divisions to assist with development of avoided cost information and renewable energy purchasing cost.

Interrogatory No. 3, cont.

Pierpont & McLelland, LLC: \$36,875.42 consisting of 200-215 hours

Charges included work to assist with development of strategic initiatives related to the FPL PPA's (\$6,229.99) and work towards the development of the contracts and agreement related to the proposed Amelia Island Energy CHP (\$30,645.43).

Sterling Energy, LLC: \$52,200.00 consisting of 345-365 hours

Charges included work to assist with the development, design and related agreements necessary for the Amelia Island Energy CHP under development.

Barry Kennedy: \$364.03 consisting of 3-5 hours

Charges included work to assist with the development and design necessary for the Amelia Island Energy CHP under development.

2022 Budget:

Christensen Associates Energy Consulting: \$20,000 consisting of 55-65 hours

Budget includes work on the PPA's with FPL for both the NE FL and NW FL divisions to renegotiate and update based on the incorporation of the Amelia Island Energy CHP under development.

Pierpont & McLelland, LLC: \$69,000 consisting of 380-400 hours

Budget includes work to assist with development of renegotiated PPA's with FPL due to the development of AIE (\$15,000) and work towards the development of the contracts and agreements related to the proposed Amelia Island Energy CHP (\$54,000).

Sterling Energy, LLC: \$120,000 consisting of 870-895 hours

Budget includes work to assist with the design, construction and related agreements necessary for the Amelia Island Energy CHP under development.

Barry Kennedy: \$0.00

Respondent: Mark Cutshaw

Interrogatory No. 4

4. For any and all project costs and related legal fees included in the 2021 fuel factor(s), please provide a description for each of the project(s) for any legal service fees incurred for working on the project(s) by project, and the amount of time the lawyer(s) have spent on each of the project(s) by project by year included in the fuel factor(s) (i.e. 2020, 2021, and 2022).

Company Response:

2020:

Gunster Yoakley & Stewart PA: \$3,722.35 consisting of 10-15 hours

Charges included work regarding the proposed Amelia Island Energy contracts and agreements (\$3,273.73) necessary to add this additional purchased power to the supply on Amelia Island and reviewing the Net Metering practices for FPU (\$448.62).

2021 YTD:

Gunster Yoakley & Stewart PA: \$1,954.82 consisting of 5-10 hours

Charges included work regarding the proposed Amelia Island Energy contracts and agreements (\$1,663.39) necessary to add this additional purchased power to the supply on Amelia Island and assistance with filing necessary documents related to this docket (\$291.43).

2022 Budget:

Gunster Yoakley & Stewart PA: \$4,000 consisting of 10-15 hours

Budget includes work regarding the proposed Amelia Island Energy contracts and agreements (\$3,500) necessary to add this additional purchased power to the supply on Amelia Island and assistance with filing necessary documents related to this docket (\$500).

Respondent: Mark Cutshaw

Interrogatory No. 5

5. Please identify the schedule(s) where the consultant and legal services fees are included in the fuel factors.

Company Response:

The consultant and legal services fees are included in Schedule E1, Page 1 on Line 10b 'Non-fuel Energy & Customer Costs of Purchased Power' of the Company's 2022 Fuel and Purchased Power Projection Exhibit CDY-3. These fees are also included in Schedule E-2 on Line 4 'Other Fuel Related Costs'.

Respondent: Curtis Young

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

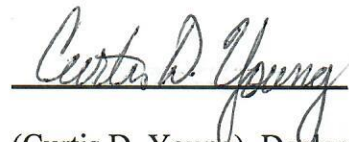
DOCKET NO. 20210001-EI

DATED: October 11, 2021

DECLARATION

I hereby certify and affirm that I sponsored the Company's responses to the OFFICE OF PUBLIC COUNSEL'S FIRST SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY, Nos. 1, 2 and 5 in Docket No. 20210001-EI. The responses are true and correct to the best of my knowledge.

Under penalty of perjury, I declare that I have read the foregoing declaration and the interrogatory responses identified above, and that the facts stated therein are true.


(Curtis D. Young), Declarant

Dated: October 11, 2021

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DOCKET NO. 20210001-EI

DATED: October 11, 2021

DECLARATION

I hereby certify and affirm that I sponsored the Company's responses to the OFFICE OF PUBLIC COUNSEL'S FIRST SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY, Nos. 3 and 4 in Docket No. 20210001-EI. The responses are true and correct to the best of my knowledge.

Under penalty of perjury, I declare that I have read the foregoing declaration and the interrogatory responses identified above, and that the facts stated therein are true.

**P. Mark
Cutshaw**

Digitally signed by P. Mark
Cutshaw
Date: 2021.10.11 10:32:26
-04'00'

(P. Mark Cutshaw), Declarant

Dated: October 11, 2021

VENDOR	True-up 2020	Projected 2021
PIERPONT AND MCLELLAND LLC	7,127.81	69,000.00
STERLING ENERGY SERVICES LLC	86,269.98	120,000.00
CHRISTENSEN ASSOCS ENERGY CONSULTING LLC	8,469.97	20,000.00
LOCKE LORD LLP	3,211.48	
GUNSTER YOAKLEY & STEWART PA	5,528.75	4,000.00
FLORIDA PUBLIC UTILITIES CO	7,118.01	8,000.00
TOTALS	117,726.00	221,000.00

Attachment OPC Rog 1-2

Interrogatory No. 1

INTERROGATORIES

For the following questions please refer to pages 3-4 of Mr. Mark Cutshaw's 2022 Projection Testimony where he briefly discusses legal and consultant fees that are included in the fuel clause.

1. Please provide the amount(s) included in the 2021 fuel factor(s) for the consulting fees.

Company Response:

Please see Excel file Revised Attachment OPC Rog 1-2.

Respondent: Curtis Young

Interrogatory No. 2

2. Please provided the amount(s) included in the 2021 fuel factor(s) for legal services fees.

Company Response:

Please see Excel file Revised Attachment OPC Rog 1-2 for Gunster, Yoakley and Stewart and Locke Lord LLP.

Respondent: Curtis Young

VENDOR	True-up 2021	Projected 2022
PIERPONT AND MCLELLAND LLC	66,139.00	69,000.00
STERLING ENERGY SERVICES LLC	87,550.00	120,000.00
CHRISTENSEN ASSOCS ENERGY CONSULTING LLC	18,513.00	20,000.00
BARRY KENNEDY	364.00	
GUNSTER YOAKLEY & STEWART PA	4,144.00	4,000.00
FLORIDA PUBLIC UTILITIES CO	9,007.00	8,000.00
TOTALS	185,717.00	221,000.00

Revised Attachment OPC Rog 1-2

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

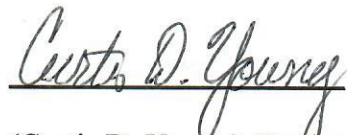
DOCKET NO. 20210001-EI

DATED: October 11, 2021

DECLARATION

I hereby certify and affirm that I sponsored the Company's responses to the OFFICE OF PUBLIC COUNSEL'S REVISED FIRST SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY, Nos. 1 AND 2 in Docket No. 20210001-EI. The responses are true and correct to the best of my knowledge.

Under penalty of perjury, I declare that I have read the foregoing declaration and the interrogatory responses identified above, and that the facts stated therein are true.



(Curtis D. Young), Declarant

Dated: October 11, 2021

DEF's Supplemental Responses to OPC's First Set of Interrogatories No. 8

DEF's Supplemental Responses to OPC's First Set of Production of Documents

No. 4.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 20210001-EI

Dated: October 19, 2021

**DUKE ENERGY FLORIDA, LLC'S SUPPLEMENTAL RESPONSE TO
CITIZENS' FIRST SET OF INTERROGATORIES (NOS. 1-8)**

Duke Energy Florida, LLC ("DEF") responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") First Set of Interrogatories to DEF (Nos. 1-8), specifically question 8, as follows:

INTERROGATORIES

Please reference the February 26, 2021 GPIF Actual Unit Performance data schedules for January 2021 in responding to interrogatories 1-8:

8. Please identify all documents related to any and all root cause analyses (or the functional equivalent, regardless of title), including drafts and related commentary correspondence, involving the forced outages occurring at Crystal River 4 in January 2021.

Answer:

Please see the documents provided in DEF's Response to OPC First Request for Production of Documents, question 4, bearing bates numbers 20210001-DEF-000048 through 20210001-DEF-000056 provided on April 9, 2021.

Please also see DEF's supplemental Response to OPC First Request for Production of Document, question 4, bearing bates numbers 20210001-DEF- 000156 through 20210001-DEF-000235.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost
Recovery Clause and Generating
Performance Incentive Factor

Docket No. 20210001-EI

Filed: October 19, 2021

**DUKE ENERGY FLORIDA, LLC'S SUPPLEMENTAL RESPONSE TO CITIZENS'
FIRST REQUEST TO PRODUCE DOCUMENTS (NOS. 1-4)**

Duke Energy Florida, LLC's ("DEF"), supplemental response to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") First Request to Produce Documents (Nos. 1-4), specifically question 4, as follows:

DOCUMENTS REQUESTED

4. Please provide the documents identified in Citizens' Interrogatory No. 8.

Response:

Please see the attached documents bearing bates numbers 20210001-DEF-000048 through 20210001-DEF-000056 provided on April 9, 2021.

Please also see the attached supplemental documents bearing bates numbers 20210001-DEF-0000156 through 20210001-DEF-000235.



Root Cause Analysis Report

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

Revision # 0.0

PlantView Event Number: 1100300

Prepared By: Barbara Martinuzzi Date: 2/2/2021

Sponsor
Approval: Wayne Toms Date: _____

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. ~~Prior to returning to service on December 16, the unit 4 main boiler feed pump tripped due to low drum level. The MBFP doesn't trip due to low drum level. Also, the MBFP wouldn't be in service prior to the unit returning to service. The MBFP is put in service after the unit reaches about 250 MW.~~

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.

~~The required NERC VAR 002 AVR Alarm Status PM had been completed on unit 4. Why is this relevant?~~

Operations closed the exciter field breaker, turbine auto sync was selected, set 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 and placed the sync switch in manual. The operator 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

20210001.EI Staff Hearing Exhibits 00188

DEF's Suppl Response to OPC POD 1 (1-4)

Q4

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	22:11:47.708	Fourth attempt (red flagged the breaker - breaker closed)
December 17, 2020	22:11:44.7340	Citrus Combined Cycle PB1 tripped (breaker open)
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.

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. *Did the operator say why they didn't reposition the synch handle one more twist to OFF? i don't like the way this is worded. i think i know what you want to say but it isn't saying that. The breaker closed before the operator had a chance to touch the switch.*

VI. Summary of Contributing Cause(s):

Note: Not necessarily listed in order of significance.

A3B2C02 – Signs to stop were ignored and step performed incorrectly

(Most activities generate indication of status (both positive and negative). The human tendency is to focus on the indications of success rather than all the indicators. The negative indicators are the "signs to stop.")

Changing priorities regarding unit operation changed multiple times in less than two hours, adding time pressure to complete the tasks and move on to additional tasks. Station was attempting to respond to meet system requirements. (unit 4 running, start up on unit 5, unit 4 tripped, put unit 5 on hold, start up unit 4, out of phase sync event happened, start up unit 5). *Once U4 tripped it required immediate response. No choice but to change priority from U5 start up to U4 recovery. Agreed that there were immediate changing priorities, but was there really time pressure during the synchronizing process?*

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. *Were all three permissive lights illuminated? Is more adjustment needed once the light is illuminated? If so, why? Talk through with Joe's graphs.*

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.)

Operations should have stopped when unit 4 initially tripped on low drum level and consulted the *Generator Trip EOP 1*. The EOP (*which EOP; BFP Trip, Boiler Trip, Turbine Trip*) provides steps for immediate operator response, protective relay targets, and associated alarms on the DCS alarm screen. Transformer, auxiliary transformers and relay trip schedules are also listed along with the lockout relay reset procedure. Through interviews it was noted that trips caused by the main boiler feed water pump were not uncommon and the EOP was typically not consulted for this type trip event.

Ops protocol states that we respond to unit emergencies, then refer to a procedure. "During a station transient or emergency situation (e.g. boiler leak, equipment tripping, fire, injury, etc.), Operators are expected to take prompt actions to ensure the safety of all personnel and place the station equipment in a safe and stable condition and then refer to appropriate procedures to verify correct actions have been taken." The plant had tripped three hours earlier and EOPs were never referenced. Start-up procedure was pulled, no documentation found for the sign off portions of the procedure.

My understanding is that a start-up procedure was pulled out to use as reference to return the unit to service. There will be an overall revision to the start-up procedure including detailed information on relay resetting including an attachment with pictures.

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 were not made available to provide adequate training for the newly restructured organization as it moved through various tier levels. CRN moved from tier 3 to tier 2 status on October 7, 2020. Experience of the OTS was less than adequate, consisting of shadowing for approximately three months and becoming full time in September 2020. Not sure how tiering impacted the event, unless you are referencing that CRN reduced supervisor positions from 11 to 6 prompting many experienced OTS to leave? The remaining and new supervisors are now responsible for Plant and FGD/WWT instead of being siloed in one area.

It isn't the OTS who is tasked with knowing how to synch the unit online. It is preferable, but not a requirement to know each technical aspect of the position being supervised.

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. Would like clarification on if the three permissive lights are illuminated, are adjustments still needed? That doesn't seem acceptable. Joe's graphs.

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	Assignee	Due/Completion Date
Describe specific actions taken or required.		

	Evaluator <u>SHALL</u> obtain concurrence from assignee or supervisor	
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 <u>SHALL</u> 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 Fleet.	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 <u>SHALL</u> 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: Performance manage employees involved in the event as appropriate. Who was identified as requiring performance management by the team? What level? Not the RCA's team call.	Jamie Long	3/1/2021
CAPR 3: Share this Root Cause Analysis with all employees at the station.	Wayne Toms	3/1/2021

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 <u>SHALL</u> obtain concurrence from assignee or supervisor	Due/Completion Date
Ensure that there is a specific lesson plan around generator synchronization and implement. Include methodical problem-solving techniques with unfamiliar situations. Two separate training tasks. Divide the problem solving training into a separate task with a later due date.	TJ Snodgrass	5/1/2021
Provide instructor led training for Operations and OTSs upon completion of the Start-up procedure and synchronizing guide revisions.	TJ Snodgrass	5/1/2021

Evaluate OTS training (technical, command and control) and consider increased shadowing time and rotation to improve proficiency. OTS will be provided extended pay to attend all training sessions and simulator training with their crews. Extended pay to review procedures and shadow craft would be desired.	Jamie Long	5/1/2021
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Action(s) to Correct the Contributing Cause(s)		
Contributing Cause (s):	<i>A5B1C01 – Format deficiencies</i> <i>A5B2C08 – Incomplete/situation not covered</i> <i>A5B2C01 – Limit inaccuracies</i>	
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)	3/1/2021
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.

20210001.EI Staff Hearing Exhibits 00193

DEF's Suppl Response to OPC POD 1 (1-4)

Q4

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

RMA 21184 DUKE
ENERGY EVALUATION

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

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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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
Time pressure	Priorities changed multiple times in a short period as the station was attempting to respond to meet system requirements.	Operations should have stopped and evaluated the situation prior to continuing to attempt synchronization (contributed to).	Signs to stop were not recognized and step performed incorrectly

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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . Apply "WHY STAIRCASE" as appropriate.
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
Operations should have stopped when unit 4 initially tripped on low drum level and consulted the Emergency Operating Procedure (EOP).	Using the startup procedure does not direct the operator to consult the EOP which provides steps for immediate operator response, protective relay targets and associated alarms on the DCS alarm screen.	Not being directed to utilize the EOP placed the operator in a skill-based scenario, outside the scope of the startup procedure, and with only knowledge to rely on. (contributed to).	Individual underestimated the problem by using past events as basis
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

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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . Apply “WHY STAIRCASE” as appropriate.
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



Root Cause Analysis Report

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

Revision # 0.0

PlantView Event Number: 1100300

Prepared By: Barbara Martinuzzi Date: 2/2/2021

Sponsor
Approval: Wayne Toms Date: _____

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. Prior to returning to service on December 16, the unit 4 main boiler feed pump tripped due to low drum level. The MBFP doesn't trip due to low drum level. Also, the MBFP wouldn't be in service prior to the unit returning to service. The MBFP is put in service after the unit reaches about 250 MW.

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.

The required NERC VAR-002 AVR Alarm Status PM had been completed on unit 4. Why is this relevant?

Operations closed the exciter field breaker, turbine auto sync was selected, set 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 and placed the sync switch in manual. The operator 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

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DEF's Suppl Response to OPC POD 1 (1-4)

Q4

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	22:11:47.708	Fourth attempt (red flagged the breaker)
December 17, 2020	22:11:44.7340	Citrus Combined Cycle PB1 tripped
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.

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

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DEF's Suppl Response to OPC POD 1 (1-4)

Q4

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. *Did the operator say why they didn't reposition the synch handle one more twist to OFF? i don't like the way this is worded. i think i know what you want to say but it isn't saying that.*

VI. Summary of Contributing Cause(s):

Note: Not necessarily listed in order of significance.

A3B2C02 – Signs to stop were ignored and step performed incorrectly

(Most activities generate indication of status (both positive and negative). The human tendency is to focus on the indications of success rather than all the indicators. The negative indicators are the "signs to stop.")

Changing priorities regarding unit operation changed multiple times in less than two hours, adding time pressure to complete the tasks and move on to additional tasks. Station was attempting to respond to meet system requirements. (unit 4 running, start-up on unit 5, unit 4 tripped, put unit 5 on hold, start-up unit 4, out of phase sync event happened, start-up unit 5). *Once U4 tripped it required immediate response. No choice but to change priority from U5 start-up to U4 recovery. Agreed that there were immediate changing priorities, but was there really time pressure during the synchronizing process?*

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. *Were all three permissive lights illuminated? Is more adjustment needed once the light is illuminated? If so, why?*

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.)

Operations should have stopped when unit 4 initially tripped on low drum level and consulted the EOP. The EOP (*which EOP; BFP Trip, Boiler Trip, Turbine Trip*) provides steps for immediate operator response, protective relay targets, and associated alarms on the DCS alarm screen. Transformer, auxiliary transformers and relay trip schedules are also listed along with the lockout relay reset procedure. Through interviews it was noted that trips caused by the main boiler feed water pump were not uncommon and the EOP was typically not consulted for this type trip event.

Ops protocol states that we respond to unit emergencies, then refer to a procedure. "During a station transient or emergency situation (e.g. boiler leak, equipment tripping, fire, injury, etc.), Operators are expected to take prompt actions to ensure the safety of all personnel and place the station equipment in a safe and stable condition and then refer to appropriate procedures to verify correct actions have been taken."

My understanding is that a start-up procedure was pulled out to use as reference to return the unit to service. There will be an overall revision to the start-up procedure including detailed information on relay resetting including an attachment with pictures.

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 were not made available to provide adequate training for the newly restructured organization as it moved through various tier levels. CRN moved from tier 3 to tier 2 status on October 7, 2020. Experience of the OTS was less than adequate, consisting of shadowing for approximately three months and becoming full time in September 2020. **Not sure how tiering impacted the event, unless you are referencing that CRN reduced supervisor positions from 11 to 6 prompting many experienced OTS to leave? The remaining and new supervisors are now responsible for Plant and FGD/WWT instead of being siloed in one area.**

It isn't the OTS who is tasked with knowing how to synch the unit online. It is preferable, but not a requirement to know each technical aspect of the position being supervised.

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. **Would like clarification on if the three permissive lights are illuminated, are adjustments still needed? That doesn't seem acceptable.**

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		
<i>A4B5C09 – Change-related documents not developed or revised</i>		
Corrective Action Describe specific actions taken or required.	Assignee Evaluator <u>SHALL</u> 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
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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 Fleet.	Joe Simpson	5/1/2021

Action(s) to Correct the Root Cause(s)		
Root Cause(s):	<i>A2B6C01 – Damaged, Defective or failed part</i> <i>A3B2C04 – Previous successes in use of rule reinforced continued use of rule</i>	
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: Performance manage employees involved in the event as appropriate. Who was identified as requiring performance management by the team? What level?	Jamie Long	3/1/2021
CAPR 3: Share this Root Cause Analysis with all employees at the station.	Wayne Toms	3/1/2021

Action to Correct the Contributing Cause(s)		
Contributing Cause(s):	<i>A3B3C04 – LTA review based on assumption that process will not change</i> <i>A4B2C04 – Resources not provided to assure adequate training was provided/ maintained</i> <i>A3B3C06 – Individual underestimated the problem by using past events as basis</i> <i>A6B2C01 – Practice or “hands-on” experience LTA</i>	
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. Include methodical problem-solving techniques with unfamiliar situations. Two separate training tasks. Divide the problem solving training into a separate task with a later due date.	TJ Snodgrass	5/1/2021
Provide instructor led training for Operations and OTSs upon completion of the Start-up procedure and synchronizing guide revisions.	TJ Snodgrass	5/1/2021
Evaluate OTS training (technical, command and control) and consider increased shadowing time and rotation to improve proficiency. OTS will be provided extended pay to attend all training sessions and	Jamie Long	5/1/2021

simulator training with their crews. Extended pay to review procedures and shadow craft would be desired.		
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Action(s) to Correct the Contributing Cause(s)		
Contributing Cause (s):	<i>A5B1C01 – Format deficiencies</i> <i>A5B2C08 – Incomplete/situation not covered</i> <i>A5B2C01 – Limit inaccuracies</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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)	3/1/2021
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 <u>SHALL</u> 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



RMA 21184 DUKE
ENERGY EVALUATION

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



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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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
Time pressure	Priorities changed multiple times in a short period as the station was attempting to respond to meet system requirements.	Operations should have stopped and evaluated the situation prior to continuing to attempt synchronization (contributed to).	Signs to stop were not recognized and step performed incorrectly

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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . Apply "WHY STAIRCASE" as appropriate.
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
Operations should have stopped when unit 4 initially tripped on low drum level and consulted the Emergency Operating Procedure (EOP).	Using the startup procedure does not direct the operator to consult the EOP which provides steps for immediate operator response, protective relay targets and associated alarms on the DCS alarm screen.	Not being directed to utilize the EOP placed the operator in a skill-based scenario, outside the scope of the startup procedure, and with only knowledge to rely on. (contributed to).	Individual underestimated the problem by using past events as basis
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

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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . Apply “WHY STAIRCASE” as appropriate.
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



Root Cause Analysis Report

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

Revision # 0.0

PlantView Event Number: 1100300

Prepared By: Barbara Martinuzzi Date: 2/2/2021

Sponsor
Approval: Wayne Toms Date: _____

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. Prior to returning to service on December 16, the unit 4 main boiler feed pump tripped due to low drum level. **The MBFP doesn't trip due to low drum level. Also, the MBFP wouldn't be in service prior to the unit returning to service. The MBFP is put in service after the unit reaches about 250 MW.**

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.

The required NERC VAR-002 AVR Alarm Status PM had been completed on unit 4. Why is this relevant?

Operations closed the exciter field breaker, turbine auto sync was selected, set 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 and placed the sync switch in manual. The operator 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

Page #2

Commented [WJJC1]: None of this information is relevant to our problem statement or the event under review for the RCA.

Commented [WJJC2]: Reword. Some such as 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; shared by both units thus only one unit can be in startup at a time. 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.

Commented [WJJC3]: Remove. This is not relevant.

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	22:11:47.708	Fourth attempt (red flagged the breaker)
December 17, 2020	22:11:44.7340	Citrus Combined Cycle PB1 tripped
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.

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. Did the operator say why they didn't reposition the synch handle one more twist to OFF? i don't like the way this is worded. i think i know what you want to say but it isn't saying that.

Commented [WJJC4]: The operator red flagged breaker 3233 expecting a failed synchronization per normal (past) function of the synchronizer relay. Operator stated it did not matter because if permissives are not met the synchronizing relay would block breaker closure.

VI. Summary of Contributing Cause(s):

Note: Not necessarily listed in order of significance.

A3B2C02 – Signs to stop were ignored and step performed incorrectly

(Most activities generate indication of status (both positive and negative). The human tendency is to focus on the indications of success rather than all the indicators. The negative indicators are the "signs to stop.")

Changing priorities regarding unit operation changed multiple times in less than two hours, adding time pressure to complete the tasks and move on to additional tasks. Station was attempting to respond to meet system requirements. (unit 4 running, start-up on unit 5, unit 4 tripped, put unit 5 on hold, start-up unit 4, out of phase sync event happened, start-up unit 5). Once U4 tripped it required immediate response. No choice but to change priority from U5 start-up to U4 recovery. Agreed that there were immediate changing priorities, but was there really time pressure during the synchronizing process?

Commented [WJJC5]: I understand what Plant Manager is saying. Priority change concern was resolved well ahead of the actions that caused the event. Is this truly time pressure??? Also I am a little unsure if what we wrote herein coincides with the cause code. Our wording should have included information about the 4 futile attempts and the signal a halt to this effort until a gameplan was developed based on results.

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. Were all three permissive lights illuminated? Is more adjustment needed once the light is illuminated? If so, why?

Commented [WJJC6]: All three permissive lights were only illuminated when Sync Scope reached 12:00. That is a function of the synch circuitry. No more adjusts are needed once all 3 lights light between 11 and 1.

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.)

Operations should have stopped when unit 4 initially tripped on low drum level and consulted the EOP. The EOP (which EOP; BFP Trip, Boiler Trip, Turbine Trip) provides steps for immediate operator response, protective relay targets, and associated alarms on the DCS alarm screen. Transformer, auxiliary transformers and relay trip schedules are also listed along with the lockout relay reset procedure. Through interviews it was noted that trips caused by the main boiler feed water pump were not uncommon and the EOP was typically not consulted for this type trip event.

Ops protocol states that we respond to unit emergencies, then refer to a procedure. "During a station transient or emergency situation (e.g. boiler leak, equipment tripping, fire, injury, etc.), Operators are expected to take prompt actions to ensure the safety of all personnel and place the station equipment in a safe and stable condition and then refer to appropriate procedures to verify correct actions have been taken."

My understanding is that a start-up procedure was pulled out to use as reference to return the unit to service. There will be an overall revision to the start-up procedure including detailed information on relay resetting including an attachment with pictures.

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 were not made available to provide adequate training for the newly restructured organization as it moved through various tier levels. CRN moved from tier 3 to tier 2 status on October 7, 2020. Experience of the OTS was less than adequate, consisting of shadowing for approximately three months and becoming full time in September 2020. **Not sure how tiering impacted the event, unless you are referencing that CRN reduced supervisor positions from 11 to 6 prompting many experienced OTS to leave? The remaining and new supervisors are now responsible for Plant and FGD/WWT instead of being siloed in one area.**

It isn't the OTS who is tasked with knowing how to synch the unit online. It is preferable, but not a requirement to know each technical aspect of the position being supervised.

Commented [WJJC7]: The information after referencing is true. The last sentence is how plants/industry Management thinks TODAY.

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. **Would like clarification on if the three permissive lights are illuminated, are adjustments still needed? That doesn't seem acceptable.**

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	Assignee	Due/Completion Date
Describe specific actions taken or required.	Evaluator SHALL obtain concurrence from assignee or supervisor	

Develop a generator synchronizing guide (operator aid) for unit 4, laminate and attach to the generator output breaker.	Jamie Long	Complete
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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 Fleet.	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: Performance manage employees involved in the event as appropriate. Who was identified as requiring performance management by the team? What level?	Jamie Long	3/1/2021
CAPR 3: Share this Root Cause Analysis with all employees at the station.	Wayne Toms	3/1/2021

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. Include methodical problem-solving techniques with unfamiliar situations. Two separate training tasks. Divide the problem solving training into a separate task with a later due date.	TJ Snodgrass	5/1/2021
Provide instructor led training for Operations and OTSs upon completion of the Start-up procedure and synchronizing guide revisions.	TJ Snodgrass	5/1/2021
Evaluate OTS training (technical, command and control) and consider increased shadowing time and rotation to improve proficiency. OTS will be provided extended pay to attend all training sessions and	Jamie Long	5/1/2021

simulator training with their crews. Extended pay to review procedures and shadow craft would be desired.		
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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 <u>SHALL</u> 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 <u>SHALL</u> 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)	3/1/2021
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 <u>SHALL</u> 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.

Page #7

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



RMA 21184 DUKE
ENERGY EVALUATION

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



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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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
Time pressure	Priorities changed multiple times in a short period as the station was attempting to respond to meet system requirements.	Operations should have stopped and evaluated the situation prior to continuing to attempt synchronization (contributed to).	Signs to stop were not recognized and step performed incorrectly

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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
Operations should have stopped when unit 4 initially tripped on low drum level and consulted the Emergency Operating Procedure (EOP).	Using the startup procedure does not direct the operator to consult the EOP which provides steps for immediate operator response, protective relay targets and associated alarms on the DCS alarm screen.	Not being directed to utilize the EOP placed the operator in a skill-based scenario, outside the scope of the startup procedure, and with only knowledge to rely on. (contributed to).	Individual underestimated the problem by using past events as basis
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

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 <u>directly led to or contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . Apply “WHY STAIRCASE” as appropriate.
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



Root Cause Analysis Report

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

Revision # 1.0

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 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 and placed the sync switch in manual. The operator 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.

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 remove the red flag from the breaker 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		
<i>A4B5C09 – Change-related documents not developed or revised</i>		
Corrective Action Describe specific actions taken or required.	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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 Fleet.	Joe Simpson	5/1/2021

Action(s) to Correct the Root Cause(s)		
Root Cause(s):	<i>A2B6C01 – Damaged, Defective or failed part</i> <i>A3B2C04 – Previous successes in use of rule reinforced continued use of rule</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> 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: Performance manage employees involved in the event as appropriate.	Jamie Long	3/15/2021
CAPR 3: 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):	<i>A3B3C04 – LTA review based on assumption that process will not change</i> <i>A4B2C04 – Resources not provided to assure adequate training was provided/ maintained</i> <i>A3B3C06 – Individual underestimated the problem by using past events as basis</i> <i>A6B2C01 – Practice or “hands-on” experience LTA</i>	
Corrective Action Describe specific actions taken or required	Assignee	Due/Completion Date

	Evaluator SHALL obtain concurrence from assignee or supervisor	
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. <i>OTS will be provided extended pay to attend all training sessions and simulator training with their crews. Extended pay to review procedures and shadow craft would be desired. (Discuss with Tara - added per Wayne)</i>	Jamie Long	5/1/2021

Action(s) to Correct the Contributing Cause(s)		
Contributing Cause (s):	<i>A5B1C01 – Format deficiencies A5B2C08 – Incomplete/situation not covered A5B2C01 – Limit inaccuracies</i>	
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)	3/1/2021
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	Assignee	Due Date

Describe specific actions required	Evaluator <u>SHALL</u> obtain concurrence from assignee or supervisor	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



RMA 21184 DUKE
ENERGY EVALUATION

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



CR Unit Start-Up
Procedure OI-1 CRNC

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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

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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



Root Cause Analysis Report

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

Revision # 1.0

PlantView Event Number: 1100300

Prepared By: Barbara Martinuzzi Date: 2/2/2021

Sponsor
Approval: Wayne Toms Date: 2/24/2021

Regional Review Committee date: _____

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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 and placed the sync switch in manual. The operator 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).

Page #2

Commented [SJ1]: Were these relays verified to not be tripped prior to the sync attempt? If so, I think we should add that.

Commented [MBJ2R1]: No. The operators did not reference any of the Emergency Operating Procedures (which list all of the relays) and the startup procedure does not address the permissives, so after each attempt, they thought that particular relay was the problem and stopped looking.

Commented [MBJ3R1]:

Commented [SJ4]: Were these relays verified to not be tripped prior to the second sync attempt? If so, I think we should add that.

Commented [MBJ5R4]: Same comment as above.

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.

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.

Page #3

Commented [SJ6]: I'm not clear on what the purpose of this paragraph is...were the 3AG&AB relays tripped for both the first and second sync attempts? Above we have that these were found tripped after the second sync attempt. Still not sure what we're trying to do with this paragraph though...

Commented [MBJ7R6]: Yes. The operators did not complete a thorough walkdown after each trip, therefore each time they attempted to sync there was another item holding them out. This particular item was missed on the first attempt by the operators due to the change in the light sequence and the operators not aware of the modification. The OTS discovered.

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 remove the red flag from the breaker prior to repositioning the synchronization switch handle.

Commented [SJ8]: Does the procedure specify to do this?

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.

Commented [MBJ9R8]: There is no guidance in the procedure for unit 4, but for unit 5 it states " IF closing the generator breaker on unit 5, THEN RED FLAG SET (CLOSE) generator output breaker 1660.

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.

Commented [SJ10]: Why would the amber permissive lights show unit was ready to sync if more adjustments were needed to allow it to sync in auto? What would trigger operator to make adjustments if all the lights indicated he was good to sync? This contributing cause doesn't make sense to me

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.

Commented [MBJ11R10]: When you exceed 3600 RPM all three lights will flicker and illuminate every time when the synchroscope reaches 12 o'clock, however it will not sync if the frequency and voltage angle are not aligned. The only way to do this is to increase speed.

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.

Commented [SJ12]: It's not clear why this contributing cause is listed - are we saying we need the same operator aid for unit 4? What would have triggered operator to know an adjustment was needed if all the lights indicated ready to sync?

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.

Commented [MBJ13R12]: Please see the information above regarding the 'ready to sync'. The operator aid is inaccurate regarding the RPM.

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.

Commented [SJ14]: I suspect only Joe and relay experts understand this paragraph - is there a way to write this so the audience of this RCA will understand this paragraph?

VIII. Repeat Event Review:

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

Commented [MBJ15R14]: I will work with Joe on the language. We have since found that both Anclote units and CRN Unit 5 already have this fail safe mechanism so only applies to CRN unit 4. Transmission is already moving forward with the corrective action.

Corrective Actions:

Immediate & Interim Corrective Actions		
<i>A4B5C09 – Change-related documents not developed or revised</i>		
Corrective Action Describe specific actions taken or required.	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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 Fleet.	Joe Simpson	5/1/2021
Action(s) to Correct the Root Cause(s)		
Root Cause(s):	<i>A2B6C01 – Damaged, Defective or failed part</i> <i>A3B2C04 – Previous successes in use of rule reinforced continued use of rule</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> 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: Performance manage employees involved in the event as appropriate.	Jamie Long	3/15/2021
CAPR 3: 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):	<i>A3B3C04 – LTA review based on assumption that process will not change</i> <i>A4B2C04 – Resources not provided to assure adequate training was provided/ maintained</i> <i>A3B3C06 – Individual underestimated the problem by using past events as basis</i> <i>A6B2C01 – Practice or “hands-on” experience LTA</i>	
Corrective Action Describe specific actions taken or required	Assignee	Due/Completion Date

	Evaluator <u>SHALL</u> obtain concurrence from assignee or supervisor	
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

Deleted: OTS will be provided extended pay to attend all training sessions and simulator training with their crews. Extended pay to review procedures and shadow craft would be desired. (Discuss with Tara - added per Wayne

Action(s) to Correct the Contributing Cause(s)		
Contributing Cause (s):	<i>A5B1C01 – Format deficiencies A5B2C08 – Incomplete/situation not covered A5B2C01 – Limit inaccuracies</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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)	3/1/2021
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 <u>SHALL</u> 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	Barbara Martinuzzi	10/18/2021

events, procedures revised as described in the corrective actions, training completed, and Transmission corrective actions complete.		
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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



RMA 21184 DUKE
ENERGY EVALUATION

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



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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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 <u>directly led to or contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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



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.)

Q4

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		
<i>A4B5C09 – Change-related documents not developed or revised</i>		
Corrective Action	Assignee	Due/Completion Date
Describe specific actions taken or required.	Evaluator SHALL obtain concurrence from assignee or supervisor	
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	Assignee	Due/Completion Date
Describe specific actions taken or required	Evaluator SHALL obtain concurrence from assignee or supervisor	
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):	<i>A2B6C01 – Damaged, Defective or failed part</i> <i>A3B2C04 – Previous successes in use of rule reinforced continued use of rule</i>	
Corrective Action	Assignee	Due/Completion Date
Describe specific actions taken or required	Evaluator SHALL obtain concurrence from assignee or supervisor	
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):	<i>A3B3C04 – LTA review based on assumption that process will not change</i> <i>A4B2C04 – Resources not provided to assure adequate training was provided/ maintained</i> <i>A3B3C06 – Individual underestimated the problem by using past events as basis</i> <i>A6B2C01 – Practice or “hands-on” experience LTA</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> 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):	<i>A5B1C01 – Format deficiencies</i> <i>A5B2C08 – Incomplete/situation not covered</i> <i>A5B2C01 – Limit inaccuracies</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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 <u>SHALL</u> 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



RMA 21184 DUKE
ENERGY EVALUATION

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



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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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



Root Cause Analysis Report

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

Revision # 0.0

PlantView Event Number: 1100300

Prepared By: Barbara Martinuzzi Date: 2/2/2021

Sponsor
Approval: Wayne Toms Date: _____

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. Prior to returning to service on December 16, the unit 4 main boiler feed pump tripped due to low drum level.

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.

The required NERC VAR-002 AVR Alarm Status PM had been completed on unit 4.

Operations closed the exciter field breaker, turbine auto sync was selected, set 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 and placed the sync switch in manual. The operator 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	22:11:47.708	Fourth attempt (red flagged the breaker)
December 17, 2020	22:11:44.7340	Citrus Combined Cycle PB1 tripped
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 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.

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

20210001.EI Staff Hearing Exhibits 00249

DEF's Suppl Response to OPC POD 1 (1-4)

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.

Q4

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.

VI. Summary of Contributing Cause(s):

Note: Not necessarily listed in order of significance.

A3B2C02 – Signs to stop were ignored and step performed incorrectly

(Most activities generate indication of status (both positive and negative). The human tendency is to focus on the indications of success rather than all the indicators. The negative indicators are the "signs to stop.")

Changing priorities regarding unit operation changed multiple times in less than two hours, adding time pressure to complete the tasks and move on to additional tasks. Station was attempting to respond to meet system requirements. (unit 4 running, start-up on unit 5, unit 4 tripped, put unit 5 on hold, start-up unit 4, out of phase sync event happened, start-up unit 5).

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.)

Operations should have stopped when unit 4 initially tripped on low drum level and consulted the EOP. The EOP provides steps for immediate operator response, protective relay targets, and associated alarms on the DCS alarm screen. Transformer, auxiliary transformers and relay trip schedules are also listed along with the lockout relay reset procedure. Through interviews it was noted that trips caused by the main boiler feed water pump were not uncommon and the EOP was typically not consulted for this type trip event.

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 were not made available to provide adequate training for the newly restructured organization as it moved through various tier levels. CRN moved from tier 3 to tier 2 status on October 7, 2020. Experience of the OTS was less than adequate, consisting of shadowing for approximately three months and becoming full time in September 2020.

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.)

20210001.EI Staff Hearing Exhibits 00250

DEF's Suppl Response to OPC POD 1 (1-4)

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.

Q4

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(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		
<i>A4B5C09 – Change-related documents not developed or revised</i>		
Corrective Action Describe specific actions taken or required.	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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 Fleet.	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 <u>SHALL</u> 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: Performance manage employees involved in the event as appropriate.	Jamie Long	3/1/2021
CAPR 3: Share this Root Cause Analysis with all employees at the station.	Wayne Toms	3/1/2021

Action to Correct the Contributing Cause(s)		
Contributing Cause(s):	<i>A3B3C04 – LTA review based on assumption that process will not change</i> <i>A4B2C04 – Resources not provided to assure adequate training was provided/ maintained</i> <i>A3B3C06 – Individual underestimated the problem by using past events as basis</i> <i>A6B2C01 – Practice or “hands-on” experience LTA</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> obtain concurrence from assignee or supervisor	Due/Completion Date
Ensure that there is a specific lesson plan around generator synchronization and implement. Include methodical problem-solving techniques with unfamiliar situations.	TJ Snodgrass	5/1/2021
Provide instructor led training for Operations and OTSs upon completion of the Start-up procedure and synchronizing guide revisions.	TJ Snodgrass	5/1/2021
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):	<i>A5B1C01 – Format deficiencies</i> <i>A5B2C08 – Incomplete/situation not covered</i> <i>A5B2C01 – Limit inaccuracies</i>	
Corrective Action Describe specific actions taken or required	Assignee Evaluator <u>SHALL</u> 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 <u>SHALL</u> 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)	3/1/2021
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 <u>SHALL</u> 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



RMA 21184 DUKE
ENERGY EVALUATION

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



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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . 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
Time pressure	Priorities changed multiple times in a short period as the station was attempting to respond to meet system requirements.	Operations should have stopped and evaluated the situation prior to continuing to attempt synchronization (contributed to).	Signs to stop were not recognized and step performed incorrectly

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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . Apply "WHY STAIRCASE" as appropriate.
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
Operations should have stopped when unit 4 initially tripped on low drum level and consulted the Emergency Operating Procedure (EOP).	Using the startup procedure does not direct the operator to consult the EOP which provides steps for immediate operator response, protective relay targets and associated alarms on the DCS alarm screen.	Not being directed to utilize the EOP placed the operator in a skill-based scenario, outside the scope of the startup procedure, and with only knowledge to rely on. (contributed to).	Individual underestimated the problem by using past events as basis
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

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 <u>directly led to</u> or <u>contributed to</u> the Event.	REASON(s) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . Apply “WHY STAIRCASE” as appropriate.
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



① *Syncro* ~~seems~~ *large words, not of one.*
should
② *sync vs Synchronize throughout*

Root Cause Analysis Report

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

Revision # 0.0

PlantView Event Number: 1100300

Prepared By: Barbara Martinuzzi Date: 2/2/2021

Sponsor
Approval: Wayne Toms Date: _____

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 ~~align~~ ^{synchronize} 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. Prior to returning to service on December 16, the governor on unit 4 main boiler feed pump was replaced and set at 60 percent capacity rather than 100 percent, restricting water flow and causing the unit trip due to low drum level. ^{Is the 60% vs 100% an issue in CAP?}

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 take the ignitors out and put unit 5 on hold and recover unit 4.

The required NERC VAR-002 AVR Alarm Status PM had been completed on unit 4.

Operations closed the exciter field breaker, turbine auto sync was selected, set breaker 3233 to close, turbine speed was set at 3602 RPM, and generator voltage verified to be within 2KV of system voltage. When the synchro scope 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 synchro scope 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 synchro scope 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 and placed the sync switch in manual. The operator 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 synchro scope rolled to the twelve o'clock position. The operator stated that they were not attempting to sync in manual rather attempting to reset the sync circuit to ^{auto 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

20210001.EI Staff Hearing Exhibits 00258

synchronize

DEF's Suppl Response to OPC POD 1 (1-4)

causing the turbine/generator to attempt to sync to the grid out of phase at a 160-degree angle.

Q4

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. (Ref PV 1100460)

The Beckwith Manual sync check relay model M-0359 (25A1) failed to pass bench testing. The failure mode allowed the closing contact to close as far out as fifty degrees from zero. The set point 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 electrical field and the unit was placed in forced outage.

generator

Timeline

December 16	22:53	Unit 4 returned to service
December 17	19:10	Turbine/generator tripped (boiler feed water pump control issue)
December 17	22:00:12.608	First attempt to auto sync (permissive 86A&B lockouts tripped)
December 17	22:00:16.924	Second attempt to auto sync (plant line 3AG & 3BG lockout relays tripped)
December 17	22:00:20.132	Third attempt to auto sync (cause for failed auto sync unknown)
December 17	22:11:47.708	Fourth attempt (red flagged the breaker)
December 17	22:11:44.7340	Citrus Combined Cycle PB1 tripped
December 17	22:11:47.7106	Unit 4 breaker 3233 tripped open (U4 placed in forced outage)
December 18		Meeting with Turbine Generator Services
December 21		Review of substation drawings, relay operational data
December 23		Beckwith manual sync check relay replaced
January 7		Unit 4 start attempt (ground on the main field)
January 20		Beckwith manual sync check relay model M-0359 (25A1) sent for failure analysis

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 acquired on February 28, 2002, 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 and has been sent for failure analysis. As of this writing, two bad boards and manual contacts failed closed have been discovered.

purchased
It was made in 2002 but relocated in 2019.

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

The plant line 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 line/breaker 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.

Prior to the 2019 Spring outage (upgrading fiber optics), 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 switch selector occurred during this outage. There have been no changes to the synchronization hard panel since original plant construction.

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

The drift is an issue but larger issue is the A/B contact latching.

Do we want to mention the report from Beckwith that they have very low return rate?

is this different than p 2?

20210001.EI Staff Hearing Exhibits 00259

DEF's Suppl Response to OPC POD 1 (1-4)

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.

Q4

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.

VI. Summary of Contributing Cause(s):

Note: Not necessarily listed in order of significance.

A3B2C02 – Signs to stop were ignored and step performed incorrectly

(Most activities generate indication of status (both positive and negative). The human tendency is to focus on the indications of success rather than all the indicators. The negative indicators are the "signs to stop.")

Changing priorities regarding unit operation changed multiple times in less than two hours, adding time pressure to complete the tasks and move on to additional tasks. Station was attempting to respond to meet system requirements. (unit 4 running, start-up on unit 5, unit 4 tripped, put unit 5 on hold, start-up unit 4, event happened, start-up unit 5).

out of phase sync

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.)

Operations should have stopped when unit 4 initially tripped on low drum level and consulted the EOP. The EOP provides steps for immediate operator response, protective relay targets, and associated alarms on the DCS alarm screen. Transformer, auxiliary transformers and relay trip schedules are also listed along with the lockout relay reset procedure. Through interviews it was noted that trips caused by the main boiler feed water pump were not uncommon and the EOP was typically not consulted for this type trip event.

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 were not made available to provide adequate training for the newly restructured organization as it moved through various tier levels. **CRN moved from tier 3 to tier 2 status on October 7, 2020.** Experience of the OTS was less than adequate, consisting of shadowing for approximately three months and becoming full time in September 2020. **This amount of training did not adequately address normal, abnormal, and emergency working conditions.**

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 2.

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 synch 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 output breaker~~. 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.

*span hand pan
where syn
controls
reside.*

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 events at Crystal River or in the Florida fleet within the last three years.

- Should we mention the powerlines good catch

Corrective Actions:**Immediate & Interim Corrective Actions**

A4B5C09 – Change-related documents not developed or revised

Corrective Action	Assignee	Due/Completion Date
Describe specific actions taken or required.	Evaluator <u>SHALL</u> obtain concurrence from assignee or supervisor	
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	Assignee	Due/Completion Date
Describe specific actions taken or required	Evaluator <u>SHALL</u> obtain concurrence from assignee or supervisor	
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 Fleet.	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	Assignee	Due/Completion Date
Describe specific actions taken or required	Evaluator <u>SHALL</u> obtain concurrence from assignee or supervisor	

CAPR 1: Replace the Beckwith Manual Sync Check Relay model M-0359 (25A1) with a new device (Work Order #).	Heath McDonald	5/1/2021
CAPR 2: Performance manage employees involved in the event as appropriate.	Jamie Long	3/1/2021
CAPR 3: Share this Root Cause Analysis with all employees at the station.	Wayne Toms	3/1/2021

Action to Correct the Contributing Cause(s)		
Contributing Cause(s):	<i>A3B3C04 – LTA review based on assumption that process will not change</i> <i>A4B2C04 – Resources not provided to assure adequate training was provided/ maintained</i> <i>A3B3C06 – Individual underestimated the problem by using past events as basis</i> <i>A6B2C01 – Practice or “hands-on” experience LTA</i>	
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. Include methodical problem-solving techniques with unfamiliar situations.	TJ Snodgrass	5/1/2021
Provide instructor led training for Operations and OTSs upon completion of the Start-up procedure and synchronizing guide revisions.	TJ Snodgrass	5/1/2021
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):	<i>A5B1C01 – Format deficiencies</i> <i>A5B2C08 – Incomplete/situation not covered</i> <i>A5B2C01 – Limit inaccuracies</i>	
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)	3/1/2021

Review existing facilities in Florida for extent of cause.	Joe Simpson	4/1/2021	Q4
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Effectiveness Review Action

Insert rows for additional EREV such as interim effectiveness review

Corrective Action Describe specific actions required	Assignee Evaluator <u>SHALL</u> 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	6/18/2021

Attachments

Attachment 1: Five (5) Why Staircase

Problem Statement: Crystal River Unit 4 generator failed to align 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 relay to perform as designed.

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

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

Attachment 2: CRN Startup Procedure #CRNOP/00/TBD/0004

PDF

CR Unit Start-Up
Procedure OI-1 CRNC

Attachment 3: Barrier(s) that should have precluded or reduced the likelihood or significance of the incident

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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 position	Synchronization to the grid should occur as close to 12 as possible, but within the zone of 11 to 1 on the synchronization scope. <i>(± 5°)</i>	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
Time pressure	Priorities changed multiple times in a short period as the station was attempting to respond to meet system requirements.	Operations should have stopped and evaluated the situation prior to continuing to attempt synchronization (contributed to).	Signs to stop were ignored and step performed incorrectly

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 <u>directly</u> 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 <u>this</u> Barrier failure. Apply "WHY STAIRCASE" as appropriate.
Turbine speed of 3602 RPM was considered a set point and not a target.	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 greater than 3602 RPM may have allowed the generator voltage and system voltage to align and the unit to sync in auto (contributed to).	LTA review based on assumption that process will not change
Operations should have stopped when unit 4 initially tripped on low drum level and consulted the EOP.	The EOP provides steps for immediate operator response, protective relay targets and associated alarms on the DCS alarm screen.	The EOP was typically not consulted for main boiler feed water pump trips as they were not uncommon (contributed to).	Individual underestimated the problem by using past events as basis
On the job training	The amount of training did not adequately address normal, abnormal, and emergency working conditions.	OTS experience consisted of shadowing for approximately three months (contributed to).	Practice or "hands-on" experience less than adequate

DEF's Suppl Response to OPC POD 1 (1-1-2021)

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 <u>directly led to or contributed to</u> the Event.	REASON(S) for BARRIER FAILURE (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented <u>this Barrier failure</u> . Apply "WHY STAIRCASE" as appropriate.
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 set points.	Operator and OTS 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

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Proposed Stipulations

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DOCKET NO. 20210001-EI
ORDER NO.
ISSUED:

PROPOSED STIPULATIONS

The following issues are proposed as Type 2¹ stipulations in this proceeding²:

I. FUEL ISSUES

Duke Energy Florida, LLC.

ISSUE 1A: Should the Commission approve DEF's Risk Management Plan?

This issue should be deferred to the 2022 Fuel Docket, with the understanding that all parties retain the right to raise any issues, concerns, or alternatives they deem appropriate. The parties recognize that deferral of this issue will result in DEF entering into no hedging transactions unless or until authorized to do so by order of the Commission.

ISSUE 1B: What is the appropriate subscription bill credit associated with DEF's Clean Energy Connection Program, approved by Order No. PSC-2021-0059-S-EI, to be included for recovery in 2022?

Stipulation: \$11,109,749.

Florida Power & Light Company

ISSUE 2A: What is the appropriate revised SoBRA factor for the 2019 projects to reflect actual construction costs that are less than the projected costs used to develop the initial SoBRA factor?

Stipulation: 0.7945%.

¹ A Type 2 stipulation occurs on an issue when the utility and staff, or the utility and at least one party adversarial to the utility, agree on the resolution of the issue and the remaining parties (including staff if they do not join in the agreement) do not object to the Commission relying on the agreed language to resolve that issue in a final order.

² The OPC position on each Type 2 stipulation stated herein is as follows:

OPC takes no position on these issues nor does it have the burden of proof related to them. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or staff as a final resolution of these issues. No person is authorized to state that the OPC is a participant in, or party to, a stipulation on these issues, either in this docket, in an order of the Commission or in a representation to a Court.

ISSUE 2B: What is the appropriate revised SoBRA factor for the 2020 projects to reflect actual construction costs that are less than the projected costs used to develop the initial SoBRA factor?

Stipulation: 0.731%

ISSUE 2C: What was the total gain under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL may recover for the period January 2020 through December 2020, and how should that gain be shared between FPL and its customers?

Stipulation: FPL's asset optimization activities in 2020 delivered total benefits of \$46,135,050. Of the total gains, FPL is allowed to retain \$3,681,030.

ISSUE 2D: What is the appropriate amount of Incremental Optimization Costs under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2020 through December 2020?

Stipulation: \$512,326.

ISSUE 2E: What is the appropriate amount of Variable Power Plant O&M Attributable to Off-System Sales under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for the period January 2020 through December 2020?

Stipulation: \$1,827,307.

ISSUE 2F: What is the appropriate amount of Variable Power Plant O&M Avoided due to Economy Purchases under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for the period January 2020 through December 2020?

Stipulation: FPL has included a credit of \$167,870 as the amount of Incremental Optimization Costs under the Asset Optimization Program for variable power plant O&M avoided due to economy purchases for the period January 2020 through December 2020.

ISSUE 2G: What is the appropriate subscription credit associated with FPL's SolarTogether Program approved by Order No. PSC-2020-0084-S-EI, to be included for recovery in 2022?

Stipulation: \$113,512,426.

ISSUE 2H: Should the Commission approve FPL's 2022 Risk Management Plan?³

Stipulation: Yes. FPL's Risk Management Plan (RMP), which was filed as Exhibit GJY-2(S), contains no natural gas financial hedging transactions pursuant to the Settlement Agreement approved in Docket No. 20210015-EI. The RMP complies with the Hedging Guidelines established by the Commission and should be approved.

ISSUE 2I: What is the appropriate revised base rate adjustment factor for the Okeechobee Clean Energy Center (OCEC) limited scope adjustment (LSA) to reflect actual construction costs that are less than the projected costs used to develop the initial factor?

Stipulation: 3.014%.

ISSUE 2J: Has FPL appropriately accounted for any redispatch related to its 2022 operation of the NFRC in its 2022 projections? If not, what adjustment, if any, should be made?

Stipulation: Yes. FPL's fuel projections for 2022 are based on the economic dispatch of its system under normal operating conditions and therefore, do not include any potential redispatch related to the operation of the NFRC, or any other contingency. FPL does not adjust its projection model to account for real-time contingencies or system conditions, that may or may not occur, that would necessitate the redispatch of generation to alleviate transmission issues. As is the case for all redispatch occurrences, any redispatch related to the operation of the NFRC will be reflected as actuals in the subsequent actual/estimated and true-up filings. The OPC reserves the right to contest any costs related to redispatch of transmission that may be included in subsequent actual/estimated and true-up filings.

Florida Public Utilities Company

ISSUE 3A: Should an adjustment be made to remove any legal and/or consultant fees included for recovery in FPUC's 2022 fuel factors?

Stipulation: OPC and the utility agree that recovery by FPUC of legal and/or consultant fees through the Fuel Clause is a broader issue involving a potential shift from past Fuel Clause precedent, as well as the consideration of recovering some, or all, of these costs in the Company's base rates. Given the complexity of this analysis and the current docket schedule, the parties agree to further discuss whether this issue is appropriate for consideration in the 2022 Fuel Proceeding, or in the Company's next base rate case. As such, the parties agree that a decision on this issue is not necessary or appropriate at this time. The parties further agree that the legal and/or consultant fees submitted for recovery in this docket will remain

³ FPL and Gulf filed a single 2022 Risk Management Plan applicable to both utilities. Document No. 11768-2021.

subject to refund or true-up in the subsequent proceeding wherein they are addressed pursuant to this stipulation.

Gulf Power Company

ISSUE 4A: Should the Commission approve FPL's 2022 Risk Management Plan?

Stipulation: Yes. FPL and Gulf filed a single 2022 Risk Management Plan (RMP) applicable to both utilities. The RMP, which was filed as Exhibit GJY-2(S), contains no natural gas hedging transactions pursuant to the Settlement Agreement approved in Docket No. 20210015-EI. The RMP complies with the Hedging Guidelines established by this Commission and should be approved.

Tampa Electric Company

ISSUE 5A: What was the total gain under TECO's Optimization Mechanism approved by Order No. PSC-2017-0456-S-EI that TECO may recover for the period January 2020 through December 2020, and how should that gain to be shared between TECO and customers?

Stipulation: Total gains were \$6,642,047. TECO customers receive \$5,356,819 and TECO receives \$1,285,228.

ISSUE 5B: Should the Commission take any action related to the optimization mechanism regarding pipeline capacity release gains or coal car leases for the period of October 21, 2021, through December 31, 2021?

Stipulation: No. The Parties agree that TECO does not intend to engage in transactions described in Paragraph 12(i)-(ii) of the proposed 2021 Settlement Agreement during that time, and that no adjustment to Asset Optimization Mechanism sharing is required (notwithstanding the 2017 Settlement Agreement). Nevertheless, the Parties agree that to the extent circumstances change, sharing can be true-up/adjusted in a future proceeding.

GENERIC FUEL ADJUSTMENT ISSUES

ISSUE 6: What are the appropriate actual benchmark levels for calendar year 2021 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?

Stipulation:

DEF: \$1,714,254

FPL: FPL's revised Asset Optimization Program approved by the Commission in Order No. PSC-16-0560-AS-EI does not rely upon the three-year average Shareholder

Incentive Benchmark specified in Order No. PSC-00-1744-PAA-EI, so it is not applicable to FPL for calendar year 2021.

Gulf: FPL's revised Asset Optimization Program approved by the Commission in Order No. PSC-16-0560-AS-EI does not rely upon the three-year average Shareholder Incentive Benchmark specified in Order No. PSC-00-1744-PAA-EI, so it is not applicable to FPL for calendar year 2021.

TECO: The company did not set an actual benchmark level for calendar year 2021. Pursuant to Tampa Electric's amended and restated settlement agreement approved by Order No. PSC-2017-0456-S-EI, the company's Optimization Mechanism replaces the non-separated wholesale energy sales incentive.

ISSUE 7: **What are the appropriate estimated benchmark levels for calendar year 2022 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?**

Stipulation:

DEF: \$1,408,076.

FPL: If the Commission approves the rate Settlement Agreement proposed in Docket No. 20210015-EI, the Asset Optimization Program contained therein does not rely upon the three-year average Shareholder Incentive Benchmark specified in Order No. PSC-00-1744-PAA-EI, so it would not be applicable to FPL for calendar year 2022.

TECO: The Company did not set an estimated benchmark level for calendar year 2022. Pursuant to Tampa Electric's amended and restated settlement agreement approved by Order No. PSC-2017-0456-S-EI, the company's Optimization Mechanism replaces the non-separated wholesale energy sales incentive.

ISSUE 8: **What are the appropriate final fuel adjustment true-up amounts for the period January 2020 through December 2020?**

Stipulation:

DEF: \$39,503,838 under-recovery, which was collected as part of DEF's Fuel Midcourse approved in Order No. PSC-2021-0328-PCO-EI.

FPL: \$72,891,803 under-recovery, which is being recovered as part of the midcourse correction approved by Order No. PSC-2021-0142-PCO-EI.

FPUC: For the period ended December 2020, the Company over-recovered \$2,937,906, reflecting an actual, end of period over recovery of \$3,235,074, as compared to the Company's projected amount.

GULF: \$6,085,680 over-recovery.

TECO: \$3,769,256 over-recovery.

ISSUE 9: **What are the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2021 through December 2021?**

Stipulation:

DEF: \$246,837,576 under-recovery.

FPL: \$288,304,271 under-recovery.

FPUC: The Company projects an under-recovery of \$680,436 for the 2021 period.

GULF: \$71,727,041 under-recovery.

TECO: \$4,094,674 under-recovery.

ISSUE 10: **What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2022 through December 2022?**

Stipulation:

DEF: \$123,418,788 under-recovery if the Rate Mitigation Plan is approved. Pursuant the Rate Mitigation Plan filed in Docket No. 20210158-EI, DEF will recover the total 2021 net true-up under-recovery of \$246,837,576 over two years (2022 and 2023). If the Rate Mitigation Plan is denied, the appropriate amount is \$246,837,576.

FPL: \$353,945,632 under-recovery.

FPUC: The appropriate true up amount is an over-recovery of \$2,257,470, which incorporates a \$75,358 over-recovery in the calculation to address tax savings, as well as \$677,060 associated with the settlement of COVID-19 related costs in Docket No. 20200194-PU.

GULF: See FPL's position stated above.

TECO: \$325,418 under-recovery.

ISSUE 11: **What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2022 through December 2022?**

Stipulation:

DEF: \$1,431,565,051, which is adjusted for line losses and excludes prior period true-up GPIF amount and CEC Bill Credits.

FPL: \$3,348,601,615 unified and jurisdictionalized, excluding prior period true-ups, FPL's portion of Asset Optimization Program gains, FPL's 2022 SolarTogether Credit amount and the unified GPIF reward.

FPUC: The appropriate projected total fuel and purchased power cost recovery amount for the period January 2022 through December 2022 is \$48,707,195.

GULF: See FPL's position above.

TECO: The total recoverable fuel and purchased power recovery amount to be collected, adjusted by the jurisdictional separation factor, is \$598,798,451.

COMPANY-SPECIFIC GENERATING PERFORMANCE INCENTIVE FACTOR ISSUES

Duke Energy Florida, LLC.

No company-specific GPIF issues for Duke Energy Florida, Inc. have been identified at this time. If such issues are identified, they shall be numbered 12A, 12B, 12C, and so forth, as appropriate.

Florida Power & Light Company

No company-specific GPIF issues for Florida Power and Light Company have been identified at this time. If such issues are identified, they shall be numbered 13A, 13B, 13C, and so forth, as appropriate.

Gulf Power Company

No company-specific GPIF issues for Gulf Power Company have been identified at this time. If such issues are identified, they shall be numbered 14A, 14B, 14C, and so forth, as appropriate.

Tampa Electric Company

No company-specific GPIF issues for Tampa Electric Company have been identified at this time. If such issues are identified, they shall be numbered 15A, 15B, 15C, and so forth, as appropriate.

GENERIC GPIF ISSUES

ISSUE 16: What is the appropriate GPIF reward or penalty for performance achieved during the period January 2020 through December 2020 for each investor-owned electric utility subject to the GPIF?

Stipulation:

DEF: \$2,657,279 reward.

FPL: \$6,390,846 reward.

FPUC: No position.

GULF: \$1,642,650 penalty.

TECO: A reward in the amount of \$3,673,726 for January 2020 through December 2020 performance to be applied to the January 2022 through December 2022 period.

ISSUE 17: What should the GPIF targets/ranges be for the period January 2022 through December 2022 for each investor-owned electric utility subject to the GPIF?

Stipulation:

DEF:

Table 17-1
GPIF Targets/Ranges for the period January-December, 2022

	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR Btu/kWh	ANOHR Btu/kWh	Savings (\$000's)
DEF	Bartow 4	82.04	85.08	191	7,758	8,075	6,738
	Crystal River 4	69.57	78.31	6,846	9,472	9,980	5,809
	Crystal River 5	74.10	79.02	3,714	9,802	10,397	5,895
	Hines 1	89.40	91.66	304	7,705	7,871	944
	Hines 2	89.32	89.84	194	7,550	7,664	751
	Hines 3	93.62	94.82	168	7,394	7,570	1,653
	Hines 4	85.09	86.44	<u>201</u>	7,057	7,237	<u>1,888</u>
	Totals			<u>11,620</u>			<u>23,677</u>

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

FPL/GULF:

Table 17-2
GPIF Targets/Ranges for the period January-December, 2022

	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR Btu/kWh	ANOHR Btu/kWh	Savings (\$000's)
FPL	Canaveral 3	81.5	84.0	61	6,726	6,804	1,321
	Ft. Myers 2	91.7	94.2	50	7,121	7,270	4,793
	Manatee 3	81.4	83.9	151	6,901	7,172	6,289
	Martin 8	87.5	90.0	113	6,967	7,061	1,782

Table 17-2
GPIF Targets/Ranges for the period January-December, 2022

FPL	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR Btu/kWh	ANOHR Btu/kWh	Savings (\$000's)
	Port Everglades 5	82.1	85.1	409	6,597	6,685	2,622
	Riviera 5	89.8	92.3	116	6,633	6,719	1,900
	Sanford 5	92.2	94.7	33	7,275	7,438	2,837
	St. Lucie 1	81.4	84.9	4,975	10,437	10,538	372
	St. Lucie 2	93.6	96.6	4,072	10,297	10,392	294
	Turkey Point 3	92.9	95.9	3,875	10,512	10,635	441
	Turkey Point 4	85.7	88.7	3,482	10,900	11,188	1,045
	Turkey Point 5	89.1	92.1	87	7,160	7,268	2,109
	West County 1	83.5	86.0	128	7,220	7,492	3,848
	West County 2	68.4	70.9	145	7,004	7,104	1,714
	West County 3	90.1	92.6	<u>183</u>	6,997	7,114	<u>2,571</u>
	Totals*			<u>17,880</u>			<u>33,938</u>

Source: GPIF Target and Range Summary (Exhibit CRR-2, Pages 6-7 of 40).

*May not compute due to rounding.

TECO:

Table 17-3
GPIF Targets/Ranges for the period January-December, 2022

TECO	Plant/Unit	Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR Btu/kWh	ANOHR Btu/kWh	Savings (\$000's)
	Big Bend 4	71.7	75.6	1,396.6	10,726	11,828	3,563.3
	Polk 1	87.7	89.9	160.0	8,855	10,440	2,111.3
	Polk 2	89.3	90.3	1,595.5	6,841	7,764	16,725.7
	Bayside 1	77.4	78.9	592.7	7,339	7,510	1,417.9
	Bayside 2	92.7	93.6	<u>458.8</u>	7,695	7,971	<u>3,855.2</u>
	Totals			<u>4,203.60</u>			<u>27,673.40</u>

Source: GPIF Target and Range Summary (Exhibit PAB-2, Document 1, Page 4 of 32).

FUEL FACTOR CALCULATION ISSUES

ISSUE 18: What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2022 through December 2022?

Stipulation:

DEF: \$1,568,750,867 if the Rate Mitigation Plan is approved. \$1,692,131,754 if the Rate Mitigation Plan is denied. Both amounts include CEC Bill Credits and the prior period true-up.

FPL/GULF: \$3,824,311,080 including separate prior period true-ups for FPL and Gulf, FPL's portion of Asset Optimization gains, FPL's 2022 SolarTogether Credit amount and the unified GPIF reward.

FPUC: The appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2022 through December 2022 is \$46,449,725, which includes prior period true-ups.

TECO: The projected net fuel and purchased power cost recovery amount to be included in the recovery factor for the period January 2022 through December 2022, adjusted by the jurisdictional separation factor, is \$598,798,451. The total recoverable fuel and purchased power cost recovery amount to be collected, including the true-up, optimization mechanism, and GPIF, adjusted for the revenue tax factor, is \$604,515,118.

ISSUE 19: **What is the appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2022 through December 2022?**

Stipulation:

DEF: Pursuant to the 2021 Settlement approved in Order No. PSC-2021-0202-AS-EI, DEF has removed the Regulatory Assessment Fee from the 2022 Projection Filing and included it with the Gross Receipts Tax on customer bills.

FPL/GULF: The revenue tax factor is comprised of the Regulatory Assessment Fee ("RAF"). FPL's 2021 Settlement Agreement proposes to remove the RAF from base and clause rates and collect it in the Gross Receipts Tax line item. As such, FPL's unified 2022 FCR Factors do not include a revenue tax factor.

FPUC: The appropriate tax revenue factor is 1.00072.

TECO: The appropriate revenue tax factor is 1.00072.

ISSUE 20: **What are the appropriate levelized fuel cost recovery factors for the period January 2022 through December 2022?**

Stipulation:

DEF: 3.986 cents/kWh (adjusted for jurisdictional losses) if the Rate Mitigation Plan is approved. 4.300 cents/kWh (adjusted for jurisdictional losses) if the Rate Mitigation Plan is denied.

FPL/GULF: FPL is proposing a unified levelized factor of 3.132 cents/kWh.

FPUC: The appropriate factor is 4.580¢ per kWh.

TECO: The appropriate factor is 3.052 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage. (Sizemore)

ISSUE 21: What are the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class?

Stipulation:

DEF:

Table 21-1
DEF Fuel Recovery Line Loss Multipliers
for the period January-December, 2022

Group	Delivery Voltage Level	Line Loss Multiplier
A	Transmission	0.98
B	Distribution Primary	0.99
C	Distribution Secondary	1.00
D	Lighting Service	1.00

Source: Schedule E1-F, Exhibit GPD-3, Part 2.

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

FPUC: The appropriate fuel recovery line loss multiplier to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class is 1.00000.

TECO:

Table 21-2
TECO Fuel Recovery Line Loss Multipliers
for the period January-December, 2022

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

Source: Schedule E1-D.

ISSUE 22: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

Stipulation:

DEF: If the Rate Mitigation Plan is approved, the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2022 through December 2022, are shown in Table 22-1(a) below:

Table 22-1(a)
Fuel Cost Recovery Factors for the period January-December, 2022

Group	Delivery Voltage Level	Fuel Cost Recovery Factors (cents/kWh)			Time of Use (cents/kWh)		
		First Tier	Second Tier	Levelized	On-Peak Multiplier 1.281	Off-Peak Multiplier 0.984	Super Off-Peak Multiplier 0.732
A	Transmission	--	--	3.912	5.011	3.849	2.864
B	Distribution Primary	--	--	3.952	5.063	3.889	2.893
C	Distribution Secondary	3.681	4.751	3.992	5.114	3.928	2.922
D	Lighting Service	--	--	3.700	--	--	--

Source: Schedule E1-E (Exhibit GPD-3, Part 2, Page 1 of 1).

If the Rate Mitigation Plan is denied, the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2022 through December 2022, are shown in Table 22-1(b) below

Table 22-1(b)
Fuel Cost Recovery Factors for the period January-December, 2022

Group	Delivery Voltage Level	Fuel Cost Recovery Factors (cents/kWh)			Time of Use (cents/kWh)		
		First Tier	Second Tier	Levelized	On-Peak Multiplier 1.281	Off-Peak Multiplier 0.984	Super Off-Peak Multiplier 0.732
A	Transmission	--	--	4.220	5.406	4.152	3.089
B	Distribution Primary	--	--	4.263	5.461	4.195	3.121
C	Distribution Secondary	3.995	5.065	4.306	5.516	4.237	3.152
D	Lighting Service	--	--	3.991	--	--	--

Source: DEF's Response to Staff's 1st POD No. 1; Alternative Schedule E1-E (Page 1 of 1).

FPL: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2022 through December 2022, are shown in Tables 22-2 and 22-3 below:

Table 22-2
FPL Fuel Cost Recovery Factors for the period January-December, 2022

Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses)				
Group	Rate Schedule	Avg. Factor (cents/kWh)	Fuel Recovery Loss Multiplier	Fuel Recovery Factor (cents/kWh)
A	RS-1, first 1,000 kWh	3.132	1.00291	2.822
	RS-1, all additional kWh	3.132	1.00291	3.822
	GS-1, SL-2, GSCU-1, WIES-1	3.132	1.00291	3.141
A-1	SL-1, OL-1, PL-1	3.069	1.00291	3.078
B	GSD-1	3.132	1.00284	3.141
C	GSLD-1, CS-1	3.132	1.00173	3.137
D	GSLD-2, CS-2, OS-2, MET	3.132	0.99371	3.112
E	GSLD-3, CS-3	3.132	0.97168	3.043
A	GST-1 On-Peak	3.445	1.00291	3.455
	GST-1 Off Peak	2.997	1.00291	3.006
	RTR-1 On-Peak			0.314
	RTR-1 Off-Peak			(0.135)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	3.445	1.00284	3.455
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.997	1.00284	3.006
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	3.445	1.00173	3.451
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.997	1.00173	3.002
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	3.445	0.99399	3.424
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.997	0.99399	2.979
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	3.445	0.97168	3.347
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.997	0.97168	2.912
F	CILC-1(D), ISST-1(D) On-Peak	3.445	0.99429	3.425
	CILC-1(D), ISST-1(D) Off-Peak	2.997	0.99429	2.980

Source: Schedule E1-E, (Exh. RBD-5, Appendix II – 2022 FCR Projections, Page 7 of 143).

Table 22-3
FPL Fuel Cost Recovery Factors for the period January-December, 2022

Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors				
Group	Rate Schedule	Average Factor (cents/kWh)	Fuel Recovery Loss Multiplier	Fuel Recovery Factor (cents/kWh)
B	GSD(T)-1 On-Peak	3.834	1.00284	3.845
	GSD(T)-1 Off-Peak	3.041	1.00284	3.050
C	GSLD(T)-1 On-Peak	3.834	1.00173	3.841
	GSLD(T)-1 Off-Peak	3.041	1.00173	3.046
D	GSLD(T)-2 On-Peak	3.834	0.99399	3.811
	GSLD(T)-2 Off-Peak	3.041	0.99399	3.023

Source: Schedule E1- E, (Exh. RBD-5, Appendix II – 2022 FCR Projections, Page 8 of 143).

FPUC: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2022 through December 2022, are shown in Tables 22-4, 22-5, and 22-6 below:

Table 22-4
FPUC Fuel Cost Recovery Factors for the period January-December, 2022

Fuel Recovery Factors – By Rate Schedule	
Rate Schedule	Levelized Adjustment (cents/kWh)
RS	7.346
GS	7.389
GSD	6.795
GSLD	6.531
LS	4.957

Source: Schedule E1, Page 3 of 3 (Exhibit CDY-3, Page 3 of 8).

Table 22-5
FPUC Fuel Cost Recovery Factors for the period January-December, 2022

Step Rate Allocation For Residential Customers (RS Rate Schedule)	
Rate Schedule and Allocation	Levelized Adjustment (cents/kWh)
RS Rate Schedule – Sales Allocation	7.346
RS Rate Schedule with less than or equal to 1,000 kWh/month	6.989
RS Rate Schedule with greater than 1,000 kWh/month	8.239

Source: Schedule E1, Page 3 of 3 (Exhibit CDY-3, Page 3 of 8).

Table 22-6
FPUC Fuel Cost Recovery Factors for the period January-December, 2022

Fuel Recovery Factors for Time Of Use – By Rate Schedule		
Rate Schedule	Levelized Adjustment On Peak (cents/kWh)	Levelized Adjustment Off Peak (cents/kWh)
RS	15.389	3.089
GS	11.389	2.389
GSD	10.795	3.545
GSLD	12.531	3.531
Interruptible	5.031	6.531

Source: Schedule E1, Page 3 of 3 (Exhibit CDY-3, Page 3 of 8).

TECO: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2022 through December 2022, are shown in Table 22-7 below:

Table 22-7
TECO Fuel Cost Recovery Factors for the period January-December, 2022

2022 Fuel Cost Recovery Factors for the period ending December, 2022				
Metering Voltage Level		Fuel Cost Recovery Factors (cents per kWh)		
		Levelized Fuel Recovery Factor	First Tier (Up to 1,000 kWh)	Second Tier (Over 1,000 kWh)
STANDARD				
	Distribution Secondary (RS only)	--	2.745	3.745
	Distribution Secondary	3.057		
	Distribution Primary	3.026		
	Transmission	2.996		
	Lighting Service	3.008		
TIME OF USE				
	Distribution Secondary- On-Peak	3.318		
	Distribution Secondary- Off-Peak	2.944		
	Distribution Primary- On-Peak	3.285		
	Distribution Primary- Off-Peak	2.915		
	Transmission – On-Peak	3.252		
	Transmission – Off-Peak	2.885		

Source: Schedule E1-E.

II. CAPACITY ISSUES

COMPANY-SPECIFIC CAPACITY COST RECOVERY FACTOR ISSUES

Duke Energy Florida, LLC.

ISSUE 23A: What adjustment amounts should the Commission approve to be refunded through the capacity clause in 2022 associated with the SoBRA III project, specifically Plants Santa Fe and Twin Rivers approved in Docket No. 20200245-EI?

Stipulation:

The Commission should approve credits of \$257,563 and \$355,679 through the capacity clause for the final cost true ups for the Santa Fe and Twin Rivers projects, respectively. The Commission should also approve credits of \$386,291 and \$533,447 for the reduction of the revenue requirements for Santa Fe and Twin Rivers, respectively, in lieu of reflecting these reductions in base rates. In addition, the Commission should approve \$7,386,099 in credits for the unexpected delay in the Charlie Creek and Sandy Creek in-service dates.

ISSUE 23B: What is the appropriate amount of costs for the Independent Spent Fuel Storage Installation (ISFSI) that DEF should be allowed to recover through the capacity cost recovery clause pursuant to DEF's 2017 Settlement?

Stipulation:

\$6,885,232.

Florida Power & Light Company

ISSUE 24A: What is the appropriate true-up adjustment amount associated with the 2019 SOBRA projects to be refunded through the capacity clause in 2022?

Stipulation: \$85,034.

ISSUE 24B: What is the appropriate true-up adjustment amount associated with the 2020 SOBRA projects to be refunded through the capacity clause in 2022?

Stipulation: \$119,716.

ISSUE 24C: What are the appropriate Indiantown non-fuel base revenue requirements to be recovered through the Capacity Clause pursuant to the Commission's approval of the Indiantown transaction in Docket No. 160154-EI for 2022?

Stipulation: Per the rate Settlement Agreement proposed in Docket No. 20210015-EI, which proposes to discontinue the recovery of Indiantown non-fuel revenue requirements through the Capacity Clause and instead proposes to recover Indiantown site revenue requirements through base rates, FPL has not included Indiantown non-fuel base revenue requirements in the 2022 Capacity Clause.

ISSUE 24D: What is the appropriate true-up adjustment amount associated with Okeechobee Clean Energy Center Generation Limited Scope Adjustment as required by Order NO. PSC-2016-0560-AS-EI?

Stipulation: \$5,055,917.

Gulf Power Company

No company-specific capacity cost recovery factor issues for Gulf Power Company have been identified at this time. If such issues are identified, they will be numbered 25A, 25B, 25C, and so forth, as appropriate.

Tampa Electric Company

No company-specific capacity cost recovery factor issues for Tampa Electric Company have been identified at this time. If such issues are identified, they will be numbered 26A, 26B, 26C, and so forth, as appropriate.

GENERIC CAPACITY COST RECOVERY FACTOR ISSUES

ISSUE 27: What are the appropriate final capacity cost recovery true-up amounts for the period January 2020 through December 2020?

Stipulation:

DEF: \$6,533,167 over-recovery.

FPL: \$3,863,612 over-recovery.

GULF: \$838,127 over-recovery.

TECO: \$3,354,779 under-recovery.

ISSUE 28: What are the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2021 through December 2021?

Stipulation:

DEF: \$3,814,896 under-recovery.

FPL: \$4,916,997 over-recovery.

GULF: \$1,687,693 over-recovery.

TECO: \$ 5,739,145 over-recovery.

ISSUE 29: What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2022 through December 2022?

Stipulation:

DEF: \$2,718,273 over-recovery.

FPL/GULF: \$11,306,429 over-recovery.

TECO: \$25,180 under-recovery.

ISSUE 30: What are the appropriate projected total capacity cost recovery amounts for the period January 2022 through December 2022?

Stipulation:

DEF: \$402,634,269.

FPL/GULF: \$291,876,857 unified for the period January 2022 through December 2022, excluding separate current and prior period true-ups for FPL and Gulf, the OCEC LSA and 2019 and 2020 SoBRA projects true-up credits.

TECO: The projected total capacity cost recovery amount for the period January 2022 through December 2022 is \$5,184,806.

ISSUE 31: What are the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2022 through December 2022?

Stipulation:

DEF: \$406,801,229.

FPL/GULF: The unified projected net purchased power capacity cost recovery amount to be recovered over the period January 2022 through December 2022 is \$275,309,761, including current and prior period true-ups, the OCEC LSA and 2019 and 2020 SoBRA projects true-up credits.

TECO: The total recoverable capacity cost recovery amount to be collected, including the true-up amount, adjusted for the revenue tax factor, is \$5,128,028.

ISSUE 32: What are the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2022 through December 2022?

Stipulation:

DEF: Base – 92.865%, Intermediate – 88.321%, Peaking – 90.678%, consistent with the 2021 Settlement approved in Order No. PSC-2021-0202-AS-EI.

FPL/GULF:

ENERGY

Retail Energy Jurisdictional Factor - Base/Solar	95.8917%
Retail Energy Jurisdictional Factor - Intermediate	94.7558%
Retail Energy Jurisdictional Factor - Peaking	95.7721%

DEMAND

Retail Demand Jurisdictional Factor - Transmission	90.2581%
Retail Demand Jurisdictional Factor - Base/Solar	95.9314%
Retail Demand Jurisdictional Factor - Intermediate	95.4287%
Retail Demand Jurisdictional Factor - Peaking	95.1837%
Retail Demand Jurisdictional Factor - Distribution	100.0000%

GENERAL PLANT

Retail General Plant Jurisdictional Factor - Labor	96.9001%
--	----------

TECO: The appropriate jurisdictional separation factor is 1.0000000.

ISSUE 33: What are the appropriate capacity cost recovery factors for the period January 2022 through December 2022?

Stipulation:

DEF: The appropriate capacity cost recovery factors for the period January 2022 through December 2022 is shown in Tables 33-1A and 33-1B below:

**Table 33-1A
DEF Capacity Cost Recovery Factors for the period January 2022 - April 2022**

Rate Class		Capacity and ISFSI Cost Recovery Factors	
		¢/kWh	\$/kW-month
Residential (RS-1, RST-1, RSL-1, RSL-2, RSS-1) At Secondary Voltage		1.103	
General Service Non-Demand (GS-1, GST-1)			
	At Secondary Voltage	0.966	
	At Primary Voltage	0.956	
	At Transmission Voltage	0.947	
General Service (GS-2)		0.683	
Lighting (LS-1)		0.285	
General Service Demand (GSD-1, GSDD-1, SS-1)			
	At Secondary Voltage		2.85
	At Primary Voltage		2.82
	At Transmission Voltage		2.79
Curtable (CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3)			
	At Secondary Voltage		1.19
	At Primary Voltage		1.18
	At Transmission Voltage		1.16
Interruptible (IS-1, IST-1, IS-2, IST-2, SS-2)			
	At Secondary Voltage		2.26
	At Primary Voltage		2.24
	At Transmission Voltage		2.21
Standby Monthly (SS-1, 2, 3)			
	At Secondary Voltage		0.274
	At Primary Voltage		0.271
	At Transmission Voltage		0.268
Standby Daily (SS-1, 2, 3)			
	At Secondary Voltage		0.130
	At Primary Voltage		0.129
	At Transmission Voltage		0.127

Source: Schedule E12-E (Exhibit GPD-3, Part 3, Page 3 of 3).

Table 33-1B
DEF Capacity Cost Recovery Factors for the period May 2022 - December 2022

Rate Class		Capacity and ISFSI Cost Recovery Factors	
		¢/kWh	\$/kW-month
Residential (RS-1, RST-1, RSL-1, RSL-2, RSS-1) At Secondary Voltage		1.181	
General Service Non-Demand (GS-1, GST-1)			
	At Secondary Voltage	1.044	
	At Primary Voltage	1.034	
	At Transmission Voltage	1.023	
General Service (GS-2)		0.730	
Lighting (LS-1)		0.304	
General Service Demand (GSD-1, GSDT-1, SS-1)			
	At Secondary Voltage		3.04
	At Primary Voltage		3.01
	At Transmission Voltage		2.98
Curtable (CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3)			
	At Secondary Voltage		1.26
	At Primary Voltage		1.25
	At Transmission Voltage		1.23
Interruptible (IS-1, IST-1, IS-2, IST-2, SS-2)			
	At Secondary Voltage		2.40
	At Primary Voltage		2.38
	At Transmission Voltage		2.35
Standby Monthly (SS-1, 2, 3)			
	At Secondary Voltage		0.292
	At Primary Voltage		0.289
	At Transmission Voltage		0.286
Standby Daily (SS-1, 2, 3)			
	At Secondary Voltage		0.139
	At Primary Voltage		0.138
	At Transmission Voltage		0.136

Source: Schedule E12-E (Exhibit GPD-3, Part 3, Page 1 of 3).

FPL/GULF: The appropriate capacity cost recovery factors for the period January 2022 through December 2022 is shown in Table 33-2 below:

Table 33-2
FPL Capacity Cost Recovery Factors for the period January-December, 2022

Rate Schedule	2022 Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	Reservation Demand Charge (RDC) \$/kW	Sum of Daily Demand Charge (SDD) \$/kW
RS1/RTR1	-	0.00239	-	-
GS1/GST1	-	0.00248	-	-
GSD1/GSDT1/HLFT1/GSD1-EV	0.81635	-	-	-
OS2	-	0.00144	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	0.90050	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	0.90087	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.81843	-	-	-
SST1T	-	-	0.10	0.05
SST1D1/SST1D2/SST1D3	-	-	0.11	0.05
CILC D/CILC G	0.91616	-	-	-
CILC T	0.88907	-	-	-
MET	0.77422	-	-	-
OL1/SL1/SL1M/PL1/OSI/II	-	0.00018	-	-
SL2/SL2M/GSCU1	-	0.00160	-	-

Source: Appendix IV – 2022 CCR Projections (Exhibit RBD-7, Page 4 of 30).

TECO: The appropriate capacity cost recovery factors for the period January 2022 through December 2022 is shown in Table 33-3 below:

Table 33-3
TECO Capacity Cost Recovery Factors for the period January-December, 2022

Rate Class and Metering Voltage	2022 Capacity Cost Recovery Factors	
	¢/kWh	\$/kW
RS	0.031	-
GS and CS	0.027	
GSD, RSD Standard		
Secondary	-	0.09
Primary		0.09
Transmission		0.09
GSD Optional		
Secondary	0.022	-
Primary	0.022	
Transmission	0.022	
GSLDPR/GSLDTPR/SBLDPR/SBLDTPR	-	0.08
GSLDSU/GSLDTSU/SBLDSU/SBLDTSU		0.07
LS-1, LS-2	0.004	-

Source: Exhibit MAS-3, Document Number 1, Page 3 of 4 (amended filing 10/1/2021).

III. EFFECTIVE DATE

ISSUE 34: What should be the effective date of the fuel adjustment factors and capacity cost recovery factors for billing purposes?

Stipulation: The new factors should be effective beginning with the first billing cycle for January 2022 through the last billing cycle for December 2022. The first billing cycle may start before January 1, 2022, and the last cycle may be read after December 31, 2022, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by this Commission.

ISSUE 35: Should the Commission approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding?

Stipulation: Yes. The Commission should approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding. The Commission should direct Staff to verify that the revised tariffs are consistent with the Commission decision.

ISSUE 36: **Should this docket be closed?**

Stipulation: This is a continuing docket and should remain open.

66

Gerald Yupp October 20, 2021, Deposition and
errata sheet.

In re: Fuel and Purchased Power Cost Recovery Clause

Deposition of:

Gerard Yupp

October 06, 2021

Vol .01

PHIPPS REPORTING
Raising the Bar!

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210001-EI
FILED OCTOBER 6, 2021

IN RE: FUEL AND PURCHASED POWER COST
RECOVERY CLAUSE WITH GENERATING
PERFORMANCE INCENTIVE FACTOR,

WEB CONFERENCE DEPOSITION OF

GERARD J. YUPP
(Noticed as Gerald J. Yupp)

Wednesday, October 20, 2021
10:01 a.m. - 11:13 a.m.

Via Web Conference

Stenographically Reported Via Web By:
Lillian Rivera, Stenographer

Job No.: 212348

1 APPEARANCES: (All appearing via web conferencing.)

2 On behalf of the Office of Public Counsel:

3 OFFICE OF PUBLIC COUNSEL
4 111 West Madison Street, Room 812
5 Tallahassee Florida 32399
6 850-488-9330
7 BY: STEPHANIE MORSE, ESQUIRE
8 BY: PATTIE CHRISTENSEN, ESQUIRE
9 BY: EMILY OAKLEY, ESQUIRE
10 morse.stephanie@leg.state.fl.us

11 On behalf of Florida Power & Light:

12 FLORIDA POWER & LIGHT COMPANY
13 700 Universive Blvd.
14 Juno Beach, Florida 33408
15 561-694-4000
16 BY: MARIA MONCADA, ESQUIRE
17 BY: DAVID LEE, ESQUIRE
18 maria.moncada@fpl.com

19

20

21 Also Present via web conferencing:
22 Interested Parties:

23 Damaris Rodriguez
24 Molly Cardi
25 Rich Hume
Diane Triplett
Chris Menendez
Ken Hoffman, appearing via telephone
Charles Rehwinkel, appearing via telephone
Bobby Pickles
Jackie Grady

26

27

28

29

30

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16		
17	(Stenographer's note: No exhibits were marked for identification.)	
18		
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1 Thereupon,
2 the following proceedings began at 10:01 a.m.:

3 STENOGRAPHER: Raise your right hand,
4 please.

5 Do you solemnly swear or affirm the
6 testimony you are about to give in this
7 matter will be the truth, the whole truth
8 and nothing but the truth so help you God?

9 THE WITNESS: Yes, I do.

10 Thereupon,

11 GERARD J. YUPP,
12 having been first duly sworn or affirmed, was examined
13 and testified as follows:

14 DIRECT EXAMINATION

15 BY MS. MORSE:

16 Q. This is Stephanie Morse with the Office of
17 Public Counsel.

18 Good morning, Mr. Yupp.

19 A. Good morning.

20 Q. And this is Ms. Oakley.

21 MS. MONCADA: Maria Moncada with
22 Florida Power & Light.

23 In the room with me is David Lee, Molly
24 Cardi and Damaris Rodriguez.

25 MR. REHWINKEL: Also on the phone is

1 Charles Rehwinkel with the Office of Public
2 Counsel. I am just observing.

3 MS. CHRISTENSEN: This is Pattie
4 Christensen. I am also observing today.

5 MR. HOFFMAN: Ken Hoffman. I am with
6 Florida Power & Light. I am also on the call
7 observing.

8 MS. MONCADA: I'd like to have an
9 understanding of who else is on the call. I
10 notice that the notice went out, and the Webex
11 information went out to a lot of people.

12 MR. HUME: Rich Hume with Florida Power &
13 Light.

14 MR. PICKLES: Bobby Pickles with Duke
15 Energy.

16 MS. MONCADA: We have a number that starts
17 with 8133.

18 MS. TRIPLETT: This is Diane Triplett with
19 Duke Energy.

20 MS. MONCADA: And then we have an 8504.
21 Is that the Public Service Commission?
22 Is it Jackie Grady?

23 MR. REHWINKEL: Perhaps it's Douglas
24 Higgins for the Public Service Commission.

25 MS. MONCADA: 727 area code?

1 MR. MENENDEZ: This is Chris Menendez with
2 Duke Energy.

3 MS. MONCADA: Good morning, Chris.

4 I do see Jackie Grady's name, and she is
5 with Gulf and FP&L.

6 MS. MORSE: Thank you for indulging us.

7 I wanted to make sure who was on the line.

8 Ms. Moncada and just to counsel, can we
9 agree that all objections, except as to the form
10 of the question, are reserved for hearing?

11 MS. MONCADA: Yes, Ms. Morse, I agree.

12 BY MS. MORSE:

13 Q. This deposition is being taken for the
14 purposes of discovery and pursuant to notice.

15 Mr. Yupp, it's possible some of the
16 information could be confidential, but it's not my goal
17 to put confidential information on the record.

18 So I am going to ask that if I ask you a
19 question that you think the answer needs to involve
20 confidential information, if you could avoid vocalizing
21 it. We can work on either me re-asking the question or
22 amend the answer.

23 First of all, Mr. Yupp, could you please
24 state your full name, your employer, your title for the
25 record, please?

1 A. Yes. My name is Gerard Yupp. I am employed
2 by Florida Power & Light Company as senior director of
3 wholesale operations.

4 **Q. Did you review the notice with the list of**
5 **documents that we asked you to bring?**

6 A. I did.

7 **Q. Did you bring those documents with you?**

8 A. Yes, I did.

9 **Q. Thank you. FP&L, who do you report to?**

10 A. I report to the vice president of energy,
11 marketing and trading.

12 **Q. Who is that?**

13 A. That is Sam Forest.

14 **Q. Do you report to anyone at NextEra?**

15 **N-E-X-T, capital E-R-A.**

16 A. I do not report to anybody at NextEra.

17 **Q. Along those lines, do you have any dotted**
18 **line responsibilities within NextEra?**

19 A. No, I do not.

20 **Q. Mr. Yupp, do you have any corrections to your**
21 **September 3rd, 2021, testimony?**

22 A. I did file an errata, just changing one of
23 the first questions in the testimony. Instead of have I
24 previously testified in the docket, it was changed to my
25 educational background. That was the only change that I

1 have had to my testimony.

2 Q. Well, just to clarify, I thought that was to
3 your -- was that a correction to your April testimony
4 instead, maybe?

5 A. Is it April? Yes, I am sorry. Yes, April.
6 There are no changes to my September 3rd testimony.

7 Q. I understand.

8 Please turn to page 3 of your September 3rd
9 testimony.

10 A. Okay. I am there.

11 Q. Okay. At line 9, your testimony refers to
12 Gulf exiting the Southern pool in 2021.

13 STENOGRAPHER: Ms. Morse, I didn't hear
14 your question. Can you repeat it?

15 BY MS. MORSE:

16 Q. Mr. Yupp, on page 3 of your testimony, your
17 testimony refers to Gulf exiting the Southern pool in
18 2021. Do you see that?

19 A. I do.

20 Q. My question was: Was it a typo? Did you
21 mean that Gulf will exit on July 2021 or 2022?

22 A. I am sorry. That should be July 1st of 2022.

23 Q. Next, Mr. Yupp, I am going to ask you to go
24 to page 2 of your testimony at line 4. This is where
25 you state the purposes of your testimony.

1 Down to line 5 of page 2, when you use the
2 word "dispatch" there, what do you mean?

3 A. The dispatch -- the dispatch costs are
4 reflective of right now what we would use in our system
5 EMS, which controls all of our units to dispatch the
6 units on a daily basis.

7 These fuel prices are -- as opposed to -- I
8 guess maybe the best way to describe it, as opposed
9 to -- let's say, for coal, where coal is charged out
10 based on the weighted average cost of it. The dispatch
11 cost would be the price that is used to dispatch the
12 unit on a day-in, day-out basis, which really reflects
13 the replacement value of fuel.

14 Q. Could you tell me why you testify about
15 dispatch?

16 I understand your reference to replacement
17 value of fuel. But could you elaborate on exactly why
18 you testified about dispatch?

19 MS. MONCADA: I object to the form.

20 Ms. Morse, it says the dispatch costs. I
21 just want to make that clear.

22 BY MS. MORSE:

23 Q. That's fine.

24 You can answer, please, Mr. Yupp.

25 A. I was going to say that I am testifying to

1 dispatch costs of fuel.

2 Q. Is your testimony that the way previous
3 dispatch in your testimony -- I'll rephrase that.

4 Does dispatch relate to both the use of the
5 cost of fuel and to the energy transfers themselves?

6 A. I am sorry. Can you clarify what you mean by
7 energy transfers?

8 Q. I think earlier, you were explaining that the
9 definition of dispatch related also in terms of
10 dispatching due to -- does that relate to power?

11 A. Yes, it does. I guess maybe to clarify, from
12 a broader level, the projections for fuel costs for --
13 in this case, let's say, 2022, are run in a model that I
14 reference in my testimony.

15 The dispatch costs of fuel is an input to
16 that model, as well as many other parameters, such as
17 unit outage, schedules, and generation unit parameters,
18 load.

19 So that is the model that is run within my
20 department, fuel being an input to the model to
21 ultimately determine what our -- project what our fuel
22 requirement will be for whatever time period we are
23 looking at.

24 Q. As you stated on page 2, line 5, you said one
25 purpose of your testimony is to explain the projections

1 for the dispatch costs, light fuel coal and natural gas.

2 But on line 6, you also say another purpose
3 is to explain projections for generating heat rates and
4 availability. Am I reading that correctly?

5 A. Yes.

6 Q. Could you explain what you mean by that in
7 your testimony, the generating heat rates and
8 availability?

9 A. Yes. Those are, again, inputs to the overall
10 model that is run to develop what our fuel requirements
11 and costs will be for the time period we are looking at.

12 So part of the input to that model would
13 be -- and these would come under generation
14 parameters -- would be e-grade curves, as well as --
15 from an availability standpoint, we would also model in
16 that time period whether a unit was going to be on a
17 planned outage or not. So that is what is meant by
18 generation unit heat rates and availabilities. Those
19 are inputs to the model as well.

20 Q. So understanding those are inputs, are you
21 saying that that data, those inputs are not -- didn't
22 come from you or your office? You get that from another
23 office? Or are you saying that you're the office that
24 prepares those inputs?

25 A. The generating unit heat rates and

1 availability, both as an input and then subsequently as
2 an output from the model, the input piece of anything
3 related to generation parameters, whether it be outage
4 schedules, unit ramp rates, minimum up and down times,
5 heat rates, whatever it may be, those inputs are
6 supplied by our power generation division.

7 **Q. Who is in charge of that power generation**
8 **division?**

9 A. Mike Arechabala is the executive vice
10 president of power generation.

11 **Q. Could you spell his last name, please?**

12 A. It's A-R-E-C-H-A-B-A-L-A.

13 **Q. Thank you.**

14 **Mr. Yupp, what does a unit availability have**
15 **to do with the dispatch costs --**

16 STENOGRAPHER: I'm sorry, Ms. Morse. I
17 couldn't hear your question.

18 BY MS. MORSE:

19 **Q. What does a unit availability have to do with**
20 **dispatch as discussed in your testimony?**

21 A. Whether or not a unit is available certainly
22 has an impact on what ultimately our fuel cost
23 projections are going to be for the period of time that
24 we're evaluating.

25 In other words, just to give an example, if

1 hypothetically one of our nuclear units was in a
2 refueling outage, which I do cover in my testimony as
3 well, then that needs to be modeled that that unit would
4 be off for whatever duration of time within the period
5 we're looking at, so we can correctly capture or at
6 least project what our fuel costs would be during that
7 period of time.

8 So all unit outages have an impact on our
9 fuel requirements, when they occur, what units they are,
10 and for the duration of each individual outage.

11 **Q. Thank you. So, Mr. Yupp, do you have a**
12 **working definition of the term "dispatch" as it relates**
13 **to determining dispatch costs?**

14 A. I guess from a general sense, dispatch
15 really -- in the manner in which I am using it really
16 covers the output of the model -- given all of the
17 inputs that go into the model, from fuel prices to load
18 forecast to generation availability, the dispatch of the
19 system, meaning given all of those inputs, how is the
20 system projected to run for the period of time that we
21 are evaluating it. That is the system dispatch.

22 **Q. Forgive me. Did you just say how the system**
23 **is projected to run?**

24 A. Yes, given the inputs to the model.

25 **Q. So along the same lines, in terms of your**

1 **cost projection testimony, do you have a working**
2 **definition of the term "re-dispatch"?**

3 A. No, I don't cover re-dispatch in my
4 testimony.

5 **Q. Do you have an understanding of the term**
6 **generally, though?**

7 A. Re-dispatch, I guess, from a very high level,
8 yes.

9 **Q. Okay. What is that?**

10 A. I would say re-dispatch, in my definition,
11 would be ultimately how you may -- or how a utility may
12 change which units are loaded or on-line at any given
13 point in time, maybe to handle some contingency on the
14 system, if there are transmission issues or reliability
15 issues.

16 I have always associated the word re-dispatch
17 with a reliability or a transmission issue.

18 **Q. As to the model that you referenced working**
19 **with that you used in your department, does that model**
20 **project system dispatch in the most efficient and**
21 **economic manner?**

22 A. Yes, it does.

23 **Q. So back to the system which forms the basis**
24 **of your projections, do you know if FP&L's generating**
25 **units is currently part of an integrated system?**

1 A. I am not sure what you mean by FP&L units
2 part of an integrated system.

3 **Q. Or like a transmission, a grid?**

4 A. Yes. FP&L's units are ultimately putting
5 power out onto a transmission grid.

6 **Q. Is Gulf still on track to exit the Southern
7 pool on July 1, 2022?**

8 A. That is my understanding.

9 **Q. So on page 3 of your testimony, you explained
10 the two distinct parts or finalizing the forecast, the
11 date ranges for January -- June 2022, and the range from
12 July 1 to December of '22.**

13 So is your testimony -- is the point of that,
14 the time period beginning July 1 is meant to coincide
15 with the in-service date of the North Florida Resiliency
16 Connection?

17 A. Yes. With the projected in-service date,
18 yes.

19 **Q. Can you explain your understanding of the
20 NFRC? That's the North Florida Resiliency Connection.**

21 A. Yes. My understanding is that is a
22 transmission line that will connect the Gulf and FP&L
23 systems and allow for the joint dispatch of the two
24 systems together.

25 **Q. I am going to go to -- please turn to page 13**

1 of your testimony.

2 A. Okay. I am there.

3 Q. Starting at line 5, you testified that,
4 quote, "Associated interchange represents energy
5 transfers that occur between the Southern pool members
6 as a result of a centralized integrated system, economic
7 dispatch." End quote.

8 That appears to be your reference to the time
9 for July 1, 2022. I think you previously testified -- I
10 just want to confirm. So after July 1, if the projected
11 NFRC is in service, and the joint dispatch with Gulf and
12 FP&L system occurs, Gulf will be leaving the Southern
13 pool.

14 So my question was: What integrated system,
15 if any, will Gulf belong to after July 1, 2022?

16 A. After July 1 of 2022, Gulf will be
17 dispatching as -- I shouldn't say Gulf. Gulf will be
18 with Florida Power & Light dispatching as an integrated
19 system.

20 Q. Please turn to page 20 of your testimony.

21 A. Okay. I am there.

22 Q. I apologize, Mr. Yupp. I read my notes
23 wrong. I meant page 2.

24 A. Okay.

25 Q. This time, I am going to line 20.

1 So there, it says that the cost included in
2 your projection reflected consolidation of FP&L and Gulf
3 systems.

4 Does that mean that your projections for 2022
5 include the results of your assumed dispatch of units of
6 both FP&L and the Legacy Gulf system?

7 A. Yes. From July through December of '22, our
8 fuel cost projections assume that Legacy Gulf and FP&L
9 will be dispatching its systems together.

10 Q. So your projections for the second half of
11 '22 is based on the assumption that Gulf and FP&L will
12 be fully integrated, and that Gulf will not rely on the
13 Southern company -- inner company interchange, the
14 Southern pool at all in the Southern half of 2022 -- the
15 second half of 2022?

16 A. That is correct.

17 Q. Are you projecting that any units will be
18 dispatched differently based on whether the Gulf system
19 operates as part of the Southern pool or is jointly
20 dispatch within the integrated FP&L system connected
21 through the NFRC?

22 A. Can you clarify? When you say if any Gulf
23 units will be dispatched differently, what is the
24 comparison? What's the baseline? Differently from
25 what?

1 **Q. If I said Gulf units, I didn't mean to. I**
2 **simply said units. But I was looking for the difference**
3 **between -- the difference between before July 1 and**
4 **after July 1, you projecting any difference in dispatch.**

5 A. Well, I think there certainly has to be a
6 difference in dispatch. It's probably an apples to
7 oranges comparison just because -- being dispatched with
8 Gulf assets dispatched as part of a pool or the Southern
9 pool, that is a much different scenario than the units
10 dispatched together with Florida Power & Light.

11 So to make a comparison is difficult. We
12 would not -- I, at least, would not know the reasons for
13 the way Gulf units dispatch in the pool today or for the
14 first six months of the period. I don't know that
15 information. I don't know how they fit into that pool.

16 I would say after Gulf exits the pool, then
17 certainly, their units could dispatch differently than
18 they have in the past, as with not being a member of the
19 pool, and, you know, dispatching economically together
20 with Florida Power & Light's units.

21 So a comparison to how they were running in
22 the past in the pool to how they will run after is a
23 difficult comparison. I am certain they will run
24 differently. I do know, though, after Gulf exits the
25 pool, that the system will be dispatched as economically

1 and efficiently as possible, given the combination of
2 both systems.

3 Q. Okay. Thank you.

4 So going to page 3 of your testimony,
5 starting at line 20, you state, "For the July through
6 December 2022 period, the projections represent
7 estimated fuel and power costs for a consolidated system
8 that is jointly dispatched after the NFRC goes into
9 service." End quote.

10 Did I read that correctly?

11 A. Yes.

12 Q. Can you describe, then, how the July through
13 December period affected the fuel cost relative to a
14 scenario where the NFRC is not in service during the
15 second half?

16 A. No, I do not have any -- I guess I would ask
17 to clarify. Are you saying a comparison between if the
18 NFRC was not in service beginning July 1 and Gulf
19 remained a member of the pool dispatching as a member of
20 the pool, versus how they would dispatch exiting the
21 pool on July 1 with FP&L?

22 Q. Yes.

23 A. Again, I do not know what Gulf's dispatch
24 would look like as a member of the pool or why Gulf's
25 dispatch looks as it does as a member of the Southern

1 pool.

2 I am not privy to that information, to those
3 inputs, to their models, to any of the other operating
4 company's units, data, the load of the system. I am not
5 privy to any of that information. So how Gulf
6 dispatches as part of the pool is all done by Southern
7 Company.

8 What I can reiterate is, again, with the NFRC
9 projected to be in service on July 1, our model to both
10 systems integrated them together, and dispatched them as
11 economically and efficiently as possible for the last
12 six months of the year.

13 **Q. So it's your testimony that FP&L did not**
14 **perform any alternate runs for projections in a scenario**
15 **where the NFRC is not in service during the second half**
16 **of '22?**

17 A. FP&L did not perform any runs. I believe
18 that Southern Company -- as I reference in my testimony,
19 Southern Company ran the first six months of the year in
20 their model, similar to what we talked about with our
21 model. I believe they did run the entire year as a
22 precautionary measure in case we -- or we may have asked
23 them just to run the entire year, which made more sense.

24 I did not look -- I did not focus on anything
25 past June of '22. The focus at that point was on

1 putting our projections together for a consolidated
2 system.

3 Q. Okay. So is it your testimony, then, that if
4 you asked Southern to do those runs for an entire year,
5 then that data was provided to you?

6 A. I believe it was, subject to check. I would
7 have to check, but I believe it was, yes.

8 Q. Okay. Can you produce that as a late file
9 exhibit if it exists?

10 MS. MONCADA: Stephanie, discovery is
11 closed. I will consider it, and we will let you
12 know. We will get back to you.

13 MS. MORSE: I appreciate that, Maria. I
14 understand it's closed. It's why we are here,
15 by agreement.

16 BY MS. MORSE:

17 Q. Mr. Yupp, please turn to page 9.

18 A. Okay. I am there.

19 Q. At the very beginning there, you have a Q and

20 A. And in your answer, you reference the system average
21 dispatch cost.

22 Mr. Yupp, will you please define that term,
23 "system average dispatch cost," as you are using it in
24 the testimony?

25 A. Yes. Again, that's just a terminology that

1 would be used to represent what the forward market for
2 gas looks like. As I mentioned in my testimony, it's by
3 pipeline and by month.

4 So just looking at one particular month, when
5 we develop our fuel forecast, the underlying -- the
6 underlying commodity price for natural gas would be
7 NYMEX. And then we build up onto a variable dispatch
8 cost.

9 So what that means is based on the forward
10 curve for natural gas, and then subsequently building up
11 those curves into what we believe a delivered cost would
12 be to our system on a variable basis, excluding firm
13 transport, that would represent -- or the system average
14 dispatch would be a terminology used to describe that.
15 That's what I am using it as here.

16 **Q. Okay. Thank you.**

17 **Next, I am going to ask you to please turn to**
18 **appendix 1 of your testimony at page 3.**

19 **A. Okay. I am there.**

20 **Q. Would you please walk through how the**
21 **dispatch cost is calculated in this document?**

22 **A. Sure. So beginning at the top of that**
23 **exhibit or table, light fuel oil -- again, the base of**
24 **light fuel oil would be a forward market. And then that**
25 **forward market is developed into what we believe a**

1 delivered cost would be. So there is variable transport
2 associated by location for us. So that's how the light
3 oil would be done.

4 Coal, our underlying commodity forecast for
5 coal is done by an outside vendor, and where the
6 commodity cost is developed into a delivered cost of
7 coal, projected delivered cost of coal. That's what
8 that represents there.

9 Natural gas dispatch price, again, the
10 underlying commodity component of that is the NYMEX
11 forward curve, as I described in my testimony. That is
12 modified or developed into a -- what we believe a
13 delivered cost of natural gas to our facilities would
14 be.

15 In the natural gas dispatch price, you can
16 see that it's broken down between firm, and there is
17 also a non-firm component. So non-firm would -- firm
18 represents what we believe the delivered cost of natural
19 gas would be on a monthly basis, utilizing our firm
20 transport positions. The non-firm is just simply a
21 higher price based on having to procure interruptible
22 transport for non-firm.

23 And then the lower half of that chart -- or
24 lower third is all of the delivery transportation that
25 we have in our portfolio that we utilize on a day-in,

1 day-out basis by pipeline.

2 Q. Okay. Looking at the data in this table, the
3 dispatch cost prices for the second half of the year are
4 generally lower than those for the first half of the
5 year.

6 Will you explain why that is?

7 A. Yes. The forward curve for natural gas has a
8 very odd shape to it right now. And as we all know,
9 there has been some extreme volatility recently in the
10 curve. But based on the uncertainty around winter
11 weather and natural gas inventories and high demand in
12 Europe and Asia, a lot of factors are going into what is
13 driving the natural gas market right now.

14 The curve is very, very highly
15 backward-dated. So, in other words, November, December,
16 January, February and March are I would say subject to
17 check right now. I don't have the market in front of
18 me. But it would be above, let's say, \$5 in MMBtu from
19 a commodity perspective.

20 In April, that price, the forward price drops
21 down probably sub \$4. So within from March of '22 to
22 April of '22, the forward market drops over \$1 for
23 MMBtu, and then remains relatively flat for the balance
24 of the year.

25 So that's what you are seeing in this table

1 here. Because the NYMEX forward curve is the underlying
2 curve that we use to develop our fuel forecast. You
3 would see the same type of shape of delivery prices that
4 we're forecasting that you're seeing in the market from
5 just a commodity perspective.

6 **Q. Earlier in your answer there, you might have**
7 **mentioned some variables like weather, other impacts on**
8 **demand.**

9 **Any other causes that would make those**
10 **dispatch prices change since the time you have projected**
11 **them that they're showing --**

12 **A. No. The dispatch price -- maybe I should**
13 **clarify. The dispatch price is not an output of the**
14 **model. It's an input to the model. The dispatch prices**
15 **represent really delivered cost curves or price curves**
16 **that we are developing as an input to the model, for**
17 **then the model to dispatch the system and the units as**
18 **economically as possible. It's not an output.**

19 **So, yes, these prices change all the time.**
20 **On the day that we utilize the forward curve, which was**
21 **August 2nd in my testimony, the dispatch prices will be**
22 **different the following day and the day after, as they**
23 **are today.**

24 **They're different than they were on August**
25 **2nd, yes. That will change what this delivered curve**

1 looks like. But it would only be due to a change in the
2 forward or NYMEX curve, which is driven by many market
3 factors that would create a change in this delivered
4 price curve.

5 MS. MONCADA: Stephanie, whenever you can
6 take a break, I am going to need just five
7 minutes.

8 MS. MORSE: We can take it now, Maria.
9 That's fine.

10 (A brief recess was taken from 10:52 a.m.
11 until 11:00 a.m.)

12 BY MS. MORSE:

13 Q. Mr. Yupp, I am going to ask you to turn to
14 page 10 of your testimony, starting at line 22 and
15 continuing over to the next page.

16 There, you testified that, quote, "The heat
17 rate equation or efficiency factors are updated as
18 appropriate based on historical unit performance and
19 projected changes due to plant upgrades, fuel grade
20 changes and" --

21 STENOGRAPHER: I hate to interrupt, but I
22 hear background noise that is overriding your
23 questions.

24 BY MS. MORSE:

25 Q. Mr. Yupp, I was just asking you about the

1 testimony on page -- starting on the bottom of page 10,
2 going over to 11.

3 Is it fair to say the available transmission
4 pathways do not factor into these heat rate equations
5 and efficiency factors?

6 A. Yes, yes, but the two are totally unrelated.
7 A transmission path and a heat rate equation, I am
8 struggling with the connection. So I guess, yes,
9 they're unrelated.

10 Q. Mr. Yupp, do you interact with Michael Score
11 or his team in preparing your testimony and the
12 information that you present to the Commission?

13 A. No, I do not.

14 Q. Do your projected costs for the 2022 dispatch
15 costs referenced in your testimony, do those costs
16 contemplate any degree of re-dispatch that would not
17 occur, absent the need to avoid imposing costs on any
18 other transmission system other than FP&L's?

19 A. I am sorry. The audio was cutting in and
20 out.

21 Can you repeat that question, please?

22 Q. Sure. Do your projected costs for 2022
23 contemplate any degree of re-dispatch that would not
24 occur absent the need to avoid imposing costs on another
25 transmission system other than the NFRC?

1 A. I am sorry. The audio is really cutting in
2 and out.

3 **Q. Can you tell me what, if anything, you heard**
4 **from that question?**

5 A. Something related to costs in 2022,
6 projections and power flowing on other systems?

7 **Q. Okay. So the question was about your**
8 **projected costs for 2022, correct?**

9 A. Yes.

10 **Q. All right. Did your projection contemplate**
11 **any degree of re-dispatch that would not occur absent**
12 **the need to avoid imposing costs on another transmission**
13 **system other than FP&L's transmission system?**

14 MS. MONCADA: Object to the form.

15 And, Stephanie, I think we are going to
16 try calling in to see if the audio from the
17 phone helps us here.

18 MS. MORSE: Okay. If he can just answer
19 first.

20 MS. MONCADA: Sure, if he heard the
21 question. I don't know if he did.

22 A. Yeah. The answer to your question is, no,
23 our model does not incorporate a projected re-dispatch
24 of our system, under any conditions. Our model is based
25 on projecting fuel costs on normal conditions on the

1 system, not for contingencies that may or may not occur.

2 MS. MORSE: Well, thank you.

3 Maria, if you guys want to call in, we can
4 break to do that now.

5 (A brief recess was taken from 11:07 a.m.
6 until 11:10 a.m.)

7 BY MS. MORSE:

8 Q. Mr. Yupp, finally, just generally as to your
9 fuel cost projections referenced in your testimony, are
10 those based on dispatching economically?

11 A. Yes, I would say economically, within
12 whatever constraints that we may have. And maybe
13 constraints is the wrong word. But within -- let's say
14 one caveat could be firm transportation limits on our
15 system.

16 So we do model what we have available on a
17 firm transportation basis. So the program will dispatch
18 as economically as it can, under whatever parameters we
19 put in the program.

20 So for the most part, it is just economic --
21 you know, as economic as possible. But there are fuel,
22 natural gas areas where we have to abide by our
23 contractual limits. So those are part of the model as
24 well.

25 MS. MORSE: Well, thank you, Mr. Yupp.

1 Those are all of my questions on direct. I may
2 have redirect. But I will turn it over for
3 other questions now.

4 MS. MONCADA: I only have one.

5 CROSS-EXAMINATION

6 BY MS. MONCADA:

7 Q. A real quick clarification. You mentioned
8 that the generation information comes from Mr.
9 Arechabala. He is the executive vice president.

10 Is there a vice president of FP&L that the
11 organization chart comes before?

12 A. Yeah, Tom Brod is the vice president of power
13 generation for Florida Power & Light.

14 MS. MONCADA: That's the only question I
15 have, Ms. Morse.

16 MS. MORSE: Okay. Well, thank you. I
17 don't have any redirect, Mr. Yupp.

18 Thank you very much for attending. I
19 think the court reporter might want to know if
20 you want to read or waive.

21 MS. MONCADA: We will read.

22 STENOGRAPHER: Ms. Morse, did you need to
23 order this?

24 MS. MORSE: Yes.

25 STENOGRAPHER: Ms. Moncada, did you want

1 to order a copy?

2 MS. MONCADA: Yes, please.

3 (The deposition was concluded at 11:13

4 a.m.)

5 (Reading and signing were not waived.)

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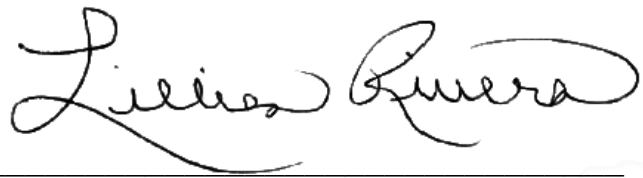
CERTIFICATE OF OATH

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THE STATE OF FLORIDA)
COUNTY OF MIAMI-DADE)

I, the undersigned authority,
certify that GERARD J. YUPP remotely appeared before me
and was duly sworn on the 20th day of October, 2021.

Signed this 28th day of October,
2021.



LILLIAN RIVERA, STENOGRAPHER
Notary Public - State of Florida
My Commission No. GG 978935
My Commission Expires: June 13, 2024

CERTIFICATE OF REPORTER

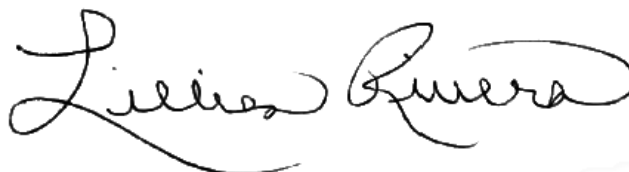
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THE STATE OF FLORIDA)
COUNTY OF MIAMI-DADE)

I, LILLIAN RIVERA, certify that I was authorized to and did stenographically report the deposition via web conference of GERARD J. YUPP, pages 1 through 31; that a review of the transcript was requested; and that the transcript is a true and complete record of my stenographic notes.

I further certify that I am not a relative, employee, attorney, or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 28th of October, 2021.



LILLIAN RIVERA, STENOGRAPHER

1 October 28, 2021

2 MARIA MONCADA, ESQUIRE
3 maria.moncada@fpl.com
4 700 Universive Blvd.
5 Juno Beach, Florida 33408

6 Re: In Re: Fuel and Purchase Power Cost Recovery Clause
7 Docket No.: 20210001-EI

8 Please take notice that on the 20th of October, 2021,
9 you gave your deposition in the above cause. At that
10 time you did not waive your signature. The transcript
11 is now available for your review.

12 Please call (888)811-3408 or e-mail
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22 reasonable amount of time, the original, which has
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25 If you wish to waive your signature now, please sign
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27 e-mail to the address listed below.

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33 _____
34 GERARD J. YUPP

35 Job No.: 212348

1 ERRATA SHEET AND OATH
2 DO NOT WRITE ON TRANSCRIPT
3 ENTER CHANGES ON THIS SHEET

3 October 28, 2021
4 Deponent: Gerard J. Yupp
5 Date of Deposition: October 20, 2021
6 Docket No: 20210001-EI
7 In Re: Fuel and Purchased Power Cost Recovery Clause

8 PAGE LINE REMARKS

9 _____
10 _____
11 _____
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17 Under penalties of perjury, I declare that I have read
18 the foregoing transcript of my deposition and I hereby
19 swear that my testimony therein was true at the time it
20 was given and is now true and correct, including any
21 corrections and/or amendments listed above.

22 Signature of witness _____

23 Dated this _____ day of _____, _____.

24 Job No.: 212348

25

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery
Clause and Generating Performance Incentive
Factor

Docket No. 20210001-EI

ERRATA SHEET

October 29, 2021

Deponent: Gerard J. Yupp

Date of Deposition: October 20, 2021 Docket No: 20210001-EI

In Re: Fuel and Purchased Power Cost Recovery Clause

<u>PAGE #</u>	<u>LINE #</u>	<u>REMARKS</u>
Page 2	Line 16	Strike "Cardi" and replace with "Carty"
Page 4	Line 24	Strike "Cardi" and replace with "Carty"
Page 7	Line 2	Strike "senior director" and replace with "Senior Director"
Page 7	Line 3	Strike "wholesale operations" and replace with "Wholesale Operations"
Page 7	Line 10	Strike "vice president of energy" and replace with "Vice President of Energy"
Page 7	Line 11	Strike "marketing and trading" and replace with "Marketing and Trading"
Page 7	Line 13	Strike "Forest" and replace with "Forrest"
Page 9	Line 12	Strike "unit" and replace with "units"
Page 10	Line 17	Strike "outage, schedules" and replace with "outage schedules"
Page 10	Line 17	Strike "and"
Page 10	Line 18	Insert "and" before "load"
Page 11	Line 14	Strike "e-grade" and replace with "heat rate"
Page 12	Line 9	Strike "executive vice" and replace with "Executive Vice"
Page 12	Line 10	Strike "president of power generation" and replace with "President of Power Generation"
Page 22	Line 7	Strike "build up onto" and replace with "build that up into"
Page 23	Line 5	Strike "and"
Page 23	Line 7	Insert "a" before "projected"
Page 24	Line 14	Strike "is very, very highly" and replace with "is very highly"
Page 24	Line 15	Strike "backward-dated" and replace with "in backwardation"
Page 24	Line 18	Strike "\$5 in" and replace with "\$5 per"
Page 24	Line 21	Insert "to" after "down"
Page 24	Line 21	Insert "per MMBtu" after "\$4"
Page 24	Line 21	Strike "within"
Page 24	Line 22	Strike "for" and replace with "per"

<u>PAGE #</u>	<u>LINE #</u>	<u>REMARKS</u>
Page 25	Line 15	Insert "the" before "delivered"
Page 25	Line 17	Strike "then"
Page 27	Line 10	Strike "Score" and replace with "Spoor"
Page 30	Line 9	Strike "executive vice president" and replace with "Executive Vice President"
Page 30	Line 12	Strike "Brod is the vice president of power" and replace with "Broad is the Vice President of Power"
Page 30	Line 13	Strike "generation" and replace with "Generation"

Under penalties of perjury, I declare that I have read my deposition and that it is true and correct, subject to any changes in form or substance entered here.

10/29/21

DATE

Gerard J. Yupp

Gerard J. Yupp

DEF's response to Staff's Fourth Interrogatories Nos. 5-7.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 20210001-EI

Dated: October 11, 2021

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 5-7)**

Duke Energy Florida, LLC ("DEF") responds to the Staff of the Florida Public Service Commission ("Staff") Fourth Set of Interrogatories (Nos. 5-7) as follows:

INTERROGATORIES

5. Please refer to the Direct Testimony of Duke Energy Florida (DEF or Company) witness Gary P. Dean, filed with DEF's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Factors for the Period of January 2022 through December 2022, Exhibit GPD-3, Part 2, Schedule E1, for the following requests.¹

- a. Are there any replacement power costs associated with the December 2020 – January 2021 outage of Crystal River Unit No. 4 contained in the amount shown on line 26?

Response:

Yes.

- b. If the response to subpart a. is yes, please identify the total replacement power cost associated with the December 2020 – January 2021 outage of Crystal River Unit No. 4 that is included for recovery in DEF's requested 2022 fuel cost recovery amount.

¹Document No. 10081-2021, filed September 3, 2021.

Response:

Total replacement power costs associated with the CR4 outage from January-April 2021 are approximately \$14.4 million retail (\$14.5 million system).

6. Please refer to the direct testimony of DEF witness Dean, Exhibit GPD-3, Part 1, page 1 of 1 for the following questions.

- a. When was the “forward” data appearing in this exhibit sourced?

Response:

The forward data was sourced at COB July 21, 2021.

- b. Assuming the Company sourced its 2022 natural gas “forward curve” pricing data in early August (2021) or before, staff observes that both spot and forward pricing (short and medium term) have increased considerably since that time. Does the Company still believe the estimated natural gas pricing data underlying its cost projection of 2022 remains adequate for setting the 2022 fuel cost recovery factor?

Response:

DEF has continued to monitor current and forward fuel prices as part of its normal operations, and as a result of the price changes witnessed, DEF is preparing an update of its fuel schedules and 2022 projected fuel factors to incorporate the updated prices in order to evaluate whether the Sept. 3rd filing requires modification.

7. Please show and explain how the projected 2022 Clean Energy Connection credit amount was formulated. Please show all calculations.

Response:

Please see the attached document bearing bates number 20210001-DEF-000074.

CEC Bill Credit Projection - Calendar Year 2022

	Unit 1			Start Month			Unit 2			Start Month			
	Rate Class	Carve Out	Subscription	Rate Class	Carve Out	Subscription							
		Allocation (MW)	Percentage		Allocation (MW)	Percentage							
Res. & Small Business	16.13	100.0%	Res. & Small Business	16.13	100.0%								
C&I	48.69	100.0%	C&I	48.69	100.0%								
Local Government	7.49	100.0%	Local Government	7.49	100.0%								
Low Income	2.60	100.0%	Low Income	2.60	100.0%								
	74.90			74.90									
Unit 1	1	2	3	4	5	6	7	8	9	10	11	12	Total
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Days Per Month	31	28	31	30	31	30	31	31	30	31	30	31	
Combined Estimated Capacity Factor (%)	0.00%	0.00%	15.11%	33.96%	34.70%	31.55%	30.36%	29.26%	28.10%	27.04%	23.49%	20.26%	
Residential & Small Business (MWh)	-	-	1,812	3,943	4,163	3,663	3,642	3,510	3,263	3,244	2,727	2,431	
C&I (MWh)	-	-	5,472	11,904	12,570	11,059	10,997	10,598	9,851	9,794	8,235	7,339	
Local Government (MWh)	-	-	842	1,831	1,934	1,701	1,692	1,631	1,516	1,507	1,267	1,129	
MW In Service	-	-	8,126	17,678	18,668	16,424	16,331	15,739	14,629	14,544	12,229	10,900	
Bill Credit Rate (cents/KWh)			4.037	4.037	4.037	4.037	4.037	4.037	4.037	4.037	4.037	4.037	4.04
Bill Credit	\$ -	\$ -	\$ 328,057	\$ 713,652	\$ 753,614	\$ 663,032	\$ 659,269	\$ 635,384	\$ 590,570	\$ 587,140	\$ 493,694	\$ 440,014	\$ 5,864,427
Residential Low Income (MW)	-	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	26.0
Bill Credit Rate (\$/KW-month)			9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03
Bill Credit	\$ -	\$ -	\$ 23,478	\$ 23,478	\$ 23,478	\$ 23,478	\$ 23,478	\$ 23,478	\$ 23,478	\$ 23,478	\$ 23,478	\$ 23,478	\$ 234,780
Total Bill Credits	\$ -	\$ -	\$ 351,535	\$ 737,130	\$ 777,092	\$ 686,510	\$ 682,747	\$ 658,862	\$ 614,048	\$ 610,618	\$ 517,172	\$ 463,492	\$ 6,099,207

AFFIDAVIT

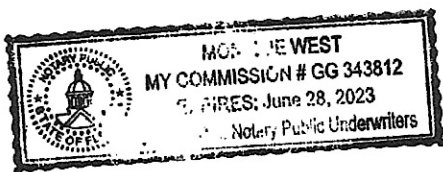
STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 6th day of October 2021, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GARY P. DEAN, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory numbers 5, 6, and 7, of STAFF'S FOURTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 5-7) in Docket No. 20210001-EI, and that the responses are true and correct based on his personal knowledge.

THE FOREGOING INSTRUMENT was sworn to and subscribed before me by means of ☐ physical presence or ☒ online (video) notarization by Gary Dean, who is personally known to me.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of October, 2021.



[Signature]
Gary P. Dean

[Signature]
Notary Public
State of Florida

My Commission Expires: 6/28/2023