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Docket No. 20190001-EI
Comprehensive Exhibit List for Entry into Hearing Record
November 5, 2019

EXH #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
DUKE ENERGY FLORIDA – (DIRECT)					
2	Christopher Menendez	CAM-1T	Fuel Cost Recovery True-Up (Jan – Dec. 2018).	1B, 1C, 6-11, 18-23, 27-37	
3	Christopher Menendez	CAM-2T	Capacity Cost Recovery True-Up (Jan – Dec. 2018). **CONFIDENTIAL DN. 01320-2019**	1B, 1C, 6-11, 18-23, 27-37	
4	Christopher Menendez	CAM-3T	Schedule A12 for Jan-Dec 2018.	1B, 1C, 6-11, 18-23, 27-37	
5	Christopher Menendez	CAM-4T	2018 Capital Structure and Cost Rates Applied to Capital Projects.	1B, 1C, 6-11, 18-23, 27-37	
6	Christopher Menendez	CAM-2	Actual/Estimated True-up Schedules for period January – December 2019.	1B, 1C, 6-11, 18-23, 27-37	
7	Christopher Menendez	CAM-3	Projection Factors for January - December 2020.	1B, 1C, 6-11, 18-23, 27-37	

8	Jeffrey Swartz[1]	JS-1	Bartow Plant Root Cause Analysis. **CONFIDENTIAL DN. 02031-2018**	1B, 1C	Not moved
9	Arnold Garcia	AG-1	Bartow CC Insurance Policy in effect on February 9, 2017. **CONFIDENTIAL DN. 01320-2019**	1B	
10	James McClay	JM-1T	Hedging True-Up August - December 2018. **CONFIDENTIAL DN. 03493-2019**	1A	
11	James McClay	JM-1P	Hedging Report (January – July 2019). **CONFIDENTIAL DN. 07514-2019**	1A	
12	James B. Daniel	JBD-1T	Calculation of GPIF Reward for January - December 2018.	16	
13	James B. Daniel	JBD-1P	GPIF Targets/Ranges Schedules for January – December 2020).	17	
FLORIDA POWER & LIGHT COMPANY – (DIRECT)					
14	R. B. Deaton	RBD-1	2018 FCR Final True Up Calculation.	6-11, 18-22	

[1] Filed in Docket No. 20180001-EI, incorporated by reference in Mr. Jeffrey Swartz's Direct Testimony filed in this docket on March 2, 2019.

15	R. B. Deaton	RBD-2	2018 CCR Final True Up Calculation. **CONFIDENTIAL DN. 01324-2019**	6-11, 18-22	
16	R. B. Deaton	RBD-3	2019 FCR Actual/Estimated True Up Calculation.	6-11, 18-22	
17	R. B. Deaton	RBD-4	2019 CCR Actual/Estimated True Up Calculation.	34	
18	R. B. Deaton	RBD-5	2018 FCR Final True Up Calculation.	6-11, 18-22	
19	R. B. Deaton	RBD-6	2018 CCR Final True Up Calculation.	27-33	
20	R. B. Deaton	RBD-7	Appendix II 2020 FCR Projection (Jan-Apr).	27-33	
21	R. B. Deaton	RBD-8	Appendix III 2020 FCR Projection (May-Dec).	27-33	
22	R. B. Deaton	RBD-9	Appendix IV 2020 FCR Projection (Jan-Dec).	27-33	
23	R. B. Deaton	RBD-10	Appendix V 2020 CCR Projection (Jan-Dec). **CONFIDENTIAL DN. 08579-2019**	27-33	
24	G. J. Yupp	GJY-1	2018 Incentive Mechanism Results. **CONFIDENTIAL DN. 01324-2019**	2C	
25	G. J. Yupp	GJY-2	Appendix I Fuel Cost Recovery.	6-11, 18	
26	C. R. Rote	CRR-1	Generating Performance Incentive Factor Performance Results for January 2018 through December 2018.	2C	

27	C. R. Rote	CRR-2	Generating Performance Incentive Factor Performance Targets for January 2020 through December 2020.	2C	
28	L. Fuentes	LF-1	2020 SoBRA Revenue Requirement Calculation.	2I	
29	L. Fuentes	LF-2	2017 SoBRA Final Revenue Requirement Calculation.	2I	
30	W. F. Brannen	WFB-1	List of FPL Universal PV Solar Energy Centers in Service.	2H	
31	W. F. Brannen	WFB-2	Typical Solar Energy Center Block Diagram.	2H	
32	W. F. Brannen	WFB-3	Renderings of 2020 Solar Energy Centers.	2H	
33	W. F. Brannen	WFB-4	Specifications for 2020 Solar Energy Centers.	2H	
34	W. F. Brannen	WFB-5	Property Delineations, Features and Land Use of 2020 Solar Energy Centers.	2H	
35	W. F. Brannen	WFB-6	Construction Schedule for 2020 Solar Energy Centers	2H	
36	J. Enjamio	JE-1	Load Forecast.	2H	
37	J. Enjamio	JE-2	FPL Fuel Price Forecast.	2H	
38	J. Enjamio	JE-3	FPL Resource Plans.	2H	
39	J. Enjamio	JE-4	CPVRR – Costs and (Benefits).	2H	
40	E. J. Anderson	EJA-1	2020 SoBRA Factor Calculation.	2J	
41	E. J. Anderson	EJA-2	Projected Retail Base Revenues for May 1, 2020.	2M	

42	E. J. Anderson	EJA-3	Summary of Tariff Changes for May 1, 2020.	2N	
43	E. J. Anderson	EJA-4	Revised 2017 SoBRA Factor.	2A, 24B	
44	E. J. Anderson	EJA-5	2017 Project Refund Calculation.	2A, 24B	
45	E. J. Anderson	EJA-6	2017 SoBRA Prospective Adjustment for Januar y 1, 2020.	2A, 24B	
46	E. J. Anderson	EJA-7	Projected Retail Base Revenues for January 1, 2020.	2K	
47	E. J. Anderson	EJA-8	Summary of Tariff Changes for January 1, 2020.	2K	
48	E. J. Anderson	EJA-9	Typical Bill Projections.	2N	
FLORIDA PUBLIC UTILITIES COMPANY – (DIRECT)					
49	Curtis D. Young	CDY-1	Final True Up Schedules (Schedules A, C1 and E1-B for FPUC's Divisions).	8, 9	
50	Curtis D. Young	CDY-2	Estimated/Actual (Schedules El-A, El-B, and El-B1).	8, 9	
51	Michelle Napier	MDN-1	Schedules E1, E1A, E2, E7, E8, E10 and Schedule A.	10, 11, 18, 19, 20, 21, 22, 34, 35, 36	
GULF POWER – (DIRECT)					
52	C. S. Boyett	CSB-1	Calculation of Final True-Up January 2018 – December 2018.	8, 27	
53	C. S. Boyett	CSB-2	A-Schedules December 2018.	8	

54	C. S. Boyett	CSB-3	Estimated True-Up January 2019 – December 2019.	6, 9, 28	
55	C. S. Boyett	CSB-4	Estímate PPCC Scherer/Flint Credit Calculation January 2019 – December 2019.	9	
56	C. S. Boyett	CSB-5	Projection January 2020 – December 2020.	7, 10, 11, 18-22, 29-33	
57	C. S. Boyett	CSB-6	Hedging Information Report August 2018 – December 2018.	4A	
58	C. S. Boyett	CSB-7	Hedging Information Report January 2019– July 2019.	4A	
59	C. L. Nicholson	CLN-1	Gulf Power Company GPIF Results January 2018 – December 2018.	16	
60	C. L. Nicholson	CLN-2	Gulf Power Company GPIF Targets and Ranges January 2020 – December 2020.	17	
TAMPA ELECTRIC COMPANY – (DIRECT)					
61	Penelope A. Rusk	PAR-1	Final True-up Capacity Cost Recovery January 2018 - December 2018. Final True-Up Fuel Cost Recovery January 2018 – December 2018. Actual Fuel True-up Compared to Original Estimates January 2018 – December 2018. Schedules A-1, A-2 and A-6 through A-9 and A-12 January 2018 – December 2018. Capital Projects Approved for Fuel Clause Recovery January 2018 – December 2018.	6, 7, 8, 9, 10, 11, 18, 19, 20, 21, 22, 27, 28, 29, 30, 31, 32, 33, 34, 35	

62	Penelope A. Rusk	PAR-2	Actual/Estimated True-Up Fuel Cost Recovery January 2019 – December 2019. Actual/Estimated True-Up Capacity Cost Recovery January 2019 – December 2019. Capital Projects Approved for Fuel Clause Recovery January 2019 – December 2019.	6, 7, 8, 9, 10, 11, 18, 19, 20, 21, 22, 27, 28, 29, 30, 31, 32, 33, 34, 35	
63	Penelope A. Rusk	PAR-3	Projected Capacity Cost Recovery January 2020 – December 2020. Projected Fuel Cost Recovery January 2020 - December 2020. Levelized and Tiered Fuel Rate January 2020– December 2020. Capital Projects Approved for Fuel Clause Recovery January 2020 – December 2020.	6, 7, 8, 9, 10, 11, 18, 19, 20, 21, 22, 27, 28, 29, 30, 31, 32, 33, 34, 35	
64	Brian S. Buckley	BSB-1	Final True-Up Generating Performance Incentive Factor January 2018 – December 2018. Actual Unit Performance Data January 2018 – December 2018.	16, 18	
65	J. Brent Caldwell	JBC-1	Final True-Up Hedging Activity Report January 2018 – December 2018.	5A	
66	Jeremy B. Cain	JC-1	Generating Performance Incentive Factor January 2020 – December 2020. Summary of Generating Performance Incentive Factor Targets January 2020 – December 2020	17	
67	John C. Heisey	JCH-1	Optimization Mechanism Results January 2018 – December 2018	5B, 18	
OFFICE OF PUBLIC COUNSEL – DIRECT					
68	Richard A. Polich, P.E.	RAP-1	Resume	1B and 1C	Not moved

69	Richard A. Polich, P.E.	RAP-2	Regulatory Testimony List	1B and 1C	Not moved
70	Richard A. Polich, P.E.	RAP-3	Bartow Combined Cycle Thermal Cycle. **CONFIDENTIAL DN. 09202-2019, X-REF. 08773-2019**	1B and 1C	Not moved
71	Richard A. Polich, P.E.	RAP-4	Turbine Generator Output Curve.	1B and 1C	Not moved
72	Richard A. Polich, P.E.	RAP-5	BCC ST Operation Greater Than 420 MW.	1B and 1C	Not moved
73	Richard A. Polich, P.E.	RAP-6	Bartow ST #1 LO Blade Upgrade To Achieve 450 MW, Dated September 18, 2013. **CONFIDENTIAL DN. 09202-2019, X-REF. 08773-2019**	1B and 1C	Not moved
74	Richard A. Polich, P.E.	RAP-7	Bartow RCA Review, Dated March 15, 2017. **CONFIDENTIAL DN. 09202-2019, X-REF. 08773-2019**	1B and 1C	Not moved
75	Richard A. Polich, P.E.	RAP-8	Update On 40'' Last Stage Blade, Dated 2015. **CONFIDENTIAL DN. 09202-2019, X-REF. 08773-2019**	1B and 1C	Not moved
76	Richard A. Polich, P.E.	RAP-9	Bartow Combined Cycle Replacement Power Costs.	1B and 1C	Not moved
STAFF – (DIRECT)					

77	Intesar Terkawi	IT-1	Auditor's Report-TECO Hedging Activities.	5A	
78	Simon O. Ojada	SOO-1	Auditor's Report DEF Hedging Activities.	1A	
79	Debra Dobiac	DMD-1	Auditor's Report Gulf Hedging Activities.	4A	
DUKE ENERGY FLORIDA – (REBUTTAL)					
80	Jeffrey Swartz	JS-2	Bartow Plant Root Cause Analysis. **CONFIDENTIAL DN. 09061-2019**	1B, 1C	Not moved
81	Jeffrey Swartz	JS-3	Bartow ST 40" Blade Test. **CONFIDENTIAL DN. 09061-2019**	1B, 1C	Not moved
82	Jeffrey Swartz	JS-4	Bartow RCA Summary. **CONFIDENTIAL DN. 09061-2019**	1B, 1C	Not moved
STAFF HEARING EXHIBITS					
83	Gerald J. Yupp (1-7) Renae B. Deaton (8)		FPL's Response to Staff's First Set of Interrogatories, Nos. 1-8 **CONFIDENTIAL DN. 03165-2019** *[Bates No. 00001-00016]*	8	

84	Gerald J. Yupp (9-16) Renae B. Deaton (17)		FPL's Response to Staff's Second Set of Interrogatories, Nos. 9-17 *[Bates No. 00017-00029]*	9	
85	William F. Brannen (18-19, 21-24) Juan E. Enjamio (20)		FPL's Response to Staff's Third Set of Interrogatories, Nos. 18-23, and 24 amended **Additional files contained on Staff Hearing Exhibits CD/USB for No. 19** *[Bates No. 00030-00040]*	2G	
86	William F. Brannen (25-26, 38) Juan E. Enjamio (27-37, 39-40)		FPL's Response to Staff's Fourth Set of Interrogatories, Nos. 25 amended) and 26-40 **Additional files contained on Staff Hearing Exhibits CD/USB for Nos. 21, 36, 37, 38, and 39** *[Bates No. 00041-00068]*	2G	
87	Juan E. Enjamio (43-51, 52, 54) William F. Brannen (53)		FPL's Response to Staff's Sixth Set of Interrogatories, Nos. 43-54 **Additional files contained on Staff Hearing Exhibits CD/USB for Nos. 45, 47, 48, 49, 50** **CONFIDENTIAL DN. 08889-2019** *[Bates No. 00069-00092]*	2H, 2I, 2J, 2K	
88	Renae B. Deaton		FPL's Response to Staff's Seventh Set of Interrogatories, No. 55b *[Bates No. 00093-00095]*	11, 18, 20, 22	
89	Renae B. Deaton		FPL's Response to Staff's Fourth Request for Production of Documents, No. 5 *[Bates No. 00096-00097]*	11, 18, 20, 22	

90	Jim McClay (1-7) Christopher A. Menendez (8)		DEF's Response to Staff's First Set of Interrogatories, Nos. 1-8 **CONFIDENTIAL DN. 03322-2019** *[Bates No. 00098-00114]*	8	
91	Christopher A. Menendez (9-17)		DEF's Response to Staff's Second Set of Interrogatories, Nos. 9-17 *[Bates No. 00115-00121]*	9	
92	Christopher A. Menendez (18)		DEF's Response to Staff's Third Set of Interrogatories, No. 18 *[Bates No. 00122-00125]*	9	
93	Mark Cutshaw (1)		FPUC's Response to Staff's First Set of Interrogatories, No. 1 *[Bates No. 00126-00130]*	8	
94	Curtis D. Young (2-10)		FPUC's Response to Staff's Second Set of Interrogatories, Nos. 2-10 *[Bates No. 00131-00147]*	9	
95	Shane Boyett (1-7)		Gulf's Response to Staff's First Set of Interrogatories, Nos. 1-7 **CONFIDENTIAL DN. 03157-2019** *[Bates No. 00148-00171]*	8	
96	Shane Boyett (8-15), C. Shane Boyett (16)		Gulf's Response to Staff's Second Set of Interrogatories, Nos. 8-16 *[Bates No. 00172-00184]*	9	
97	John Heisey		TECO's Response to Staff's First Set of Interrogatories, Nos. 1-7 **CONFIDENTIAL DN. 03169-2019** *[Bates No. 00185-00200]*	8	

98	John Heisey (8-15) Penelope Rusk (16)		TECO's Response to Staff's Second Set of Interrogatories, Nos. 8-16 *[Bates No. 00201-00218]*	9	
99	Penelope Rusk		TECO's Response to Staff's Third Set of Interrogatories, Nos. 17-18 **CONFIDENTIAL DN. 09112-2019** *[Bates No. 00219-00222]*	11	

HEARING EXHIBITS

Live Exhibit Number	Witness	Party	Description		Moved In/Due Date of Late Filed
100	Jeffrey Swartz	DEF	DEF's Responses to OPC's Fifth Set of Interrogatories (Nos. 32-35) - Issue 1C Written responses only, Attachments not included.		Not moved

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

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 2
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: Christopher Menendez

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

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

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

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

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

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

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

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

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

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

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

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 3
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: Christopher Menendez CAM-2T

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

		JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	Total
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	60,858,765
3	Orlando Cogen Limited (ORLACOGL)	5,102,804	5,102,804	5,102,804	5,102,804	5,089,383	5,094,138	5,096,530	5,099,746	5,097,899	4,988,662	5,015,745	5,023,523	60,916,840
4	Pasco County Resource Recovery (PASCOUNT)	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	21,417,600
5	Pinellas County Resource Recovery (PINCOUNT)	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	50,983,200
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,733,888	6,656,139	6,675,150	6,669,159	6,662,563	6,900,122	6,965,675	6,965,675	6,965,675	6,965,675	6,965,675	6,965,675	82,091,070
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	1,097,143	646,573	648,924	678,961	684,116	705,834	719,623	750,224	765,134	751,969	754,931	755,868	8,959,300
8	US EcoGen	0	0	0	(3,000)	(90,000)	(93,000)	(90,000)	(93,000)	(93,000)	(90,000)	(93,000)	(90,000)	(735,000)
9	Calpine Osprey	92,394	0	0	0	0	0	0	0	0	0	0	0	92,394
10	Subtotal - Base Level Capacity Costs	24,131,193	23,510,479	23,531,842	23,552,887	23,451,026	23,712,058	23,796,792	23,827,608	23,840,671	23,721,270	23,748,315	23,760,029	284,584,168
11	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
12	Base Level Jurisdictional Capacity Costs	22,414,258	21,837,709	21,857,551	21,877,099	21,782,485	22,024,945	22,103,650	22,132,273	22,144,407	22,033,501	22,058,622	22,069,503	264,336,004
13	**Intermediate Production Level Capacity Costs**													
14	Southern Franklin	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,236,165	6,252,703	4,638,320	2,750,085	2,698,716	3,488,522	49,537,060
15	Schedule H Capacity Sales - NSB, RCID & Tallahassee	0	0	0	0	0	0	(73,253)	0	0	(75,671)	(6,305)	(37,835)	(193,065)
16	Subtotal - Intermediate Level Capacity Costs	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,162,912	6,252,703	4,638,320	2,674,414	2,692,410	3,450,687	49,343,995
17	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
18	Intermediate Level Jurisdictional Capacity Costs	3,261,098	3,366,345	1,943,775	1,940,776	2,148,965	4,404,288	4,480,622	4,545,903	3,372,198	1,944,379	1,957,463	2,508,753	35,874,565
19	**Peaking Production Level Capacity Costs**													
20	Shady Hills	1,954,260	1,954,260	1,395,900	1,374,300	1,924,020	3,912,300	3,912,300	3,912,300	1,825,740	1,149,734	1,374,300	1,984,500	26,673,914
21	Vandolah (NSG)	2,924,309	2,889,528	1,965,274	1,943,845	2,795,467	5,785,430	5,768,280	5,707,232	2,712,726	1,918,109	2,015,348	2,943,834	39,369,382
22	Other	-	-	-	-	-	-	-	-	-	-	-	-	
23	Subtotal - Peaking Level Capacity Costs	4,878,569	4,843,788	3,361,174	3,318,145	4,719,487	9,697,729.55	9,680,580	9,619,532	4,538,466	3,067,843	3,389,648	4,928,334	66,043,296
24	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
25	Peaking Level Jurisdictional Capacity Costs	4,679,718	4,646,355	3,224,173	3,182,897	4,527,121	9,302,450	9,286,000	9,227,440	4,353,478	2,942,798	3,251,486	4,727,455	63,351,371
26	**Other Capacity Costs**													
27	Retail Wheeling	(23,615)	(2,605)	(13,552)	(1,023)	(49,903)	(27)	(9,282)	(6,007)	(3,342)	(4,243)	0	(1,766)	(115,365)
28	RRSSA Second Amendment [1]													
29	Batch-19 Nuclear Fuel [2]													
30	ASC Servicing Fees [3]	-	-	-	-	-	-	(296,269)	-	(160,182)	-	-	-	(456,451)
31	Total Other Capacity Costs	1,768,743	1,785,790	1,770,879	1,779,445	1,726,601	1,772,514	1,463,027	1,758,607	1,597,128	1,752,444	1,638,849	1,633,119	20,447,145
32	**Total Capacity Costs (Line 12+18+25+31)**	32,123,817	31,636,198	28,796,378	28,780,217	30,185,172	37,504,197	37,333,298	37,664,224	31,467,211	28,673,122	28,906,420	30,938,830	384,009,086
33	**Nuclear Cost Recovery Clause**													
34	CR3 Uprate Costs	4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
35	**Total Recoverable Nuclear Costs**	4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
36														
37	**ISFSI Revenue Requirement** [4]	-	-	-	-	-	-	724,926	726,807	728,105	735,486	747,111	751,681	4,414,116
38	**Total Recov Capacity & Nuclear Costs (Line 32+35+37)**	36,583,010	36,067,968	33,200,724	33,157,137	34,534,669	41,826,271	42,352,873	42,658,257	36,435,117	33,620,985	33,838,484	35,848,041	440,123,535
39	**Capacity Revenues:**													
40	Capacity Cost Recovery Revenues (net of tax)	28,519,282	29,627,699	28,061,262	31,308,667	35,187,257	38,498,070	41,592,488	41,953,532	41,807,961	36,803,224	34,335,381	30,808,440	418,503,263
41	Prior Period True-Up Provision Over/(Under) Recovery	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	14,665,233
42	Current Period CCR Revenues (net of tax)	29,741,384	30,849,802	29,283,365	32,530,770	36,409,359	39,720,172	42,814,591	43,175,635	43,030,063	38,025,327	35,557,484	32,030,543	433,168,496
43	**True-Up Provision**													
44	True-Up Provision - Over/(Under) Recov (Line 42-38)	(6,841,625)	(5,218,166)	(3,917,359)	(626,367)	1,874,691	(2,106,098)	461,718	517,378	6,594,946	4,404,342	1,719,000	(3,817,498)	(6,955,039)
45	Interest Provision for the Month	7,805	3,244	(128)	(2,766)	(3,217)	(4,786)	(7,065)	(7,661)	(4,569)	(1,419)	19	(2,658)	(23,204)
46	Current Cycle Balance - Over/(Under)	(6,833,820)	(12,048,743)	(15,966,230)	(16,595,364)	(14,723,890)	(16,834,773)	(16,380,120)	(15,870,403)	(9,280,027)	(4,877,104)	(3,158,085)	(6,978,242)	(6,978,242)
47	Prior Period Balance - Over/(Under) Recovered	16,868,292	15,646,189	14,424,086	13,201,983	11,979,880	10,757,777	9,535,675	8,313,572	7,091,469	5,869,366	4,647,263	3,425,160	16,868,292
48	Prior Period Cumulative True-Up Collected/(Refunded)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(14,665,234)
49	Prior Period True-up Balance - Over/(Under)	15,646,189	14,424,086	13,201,983	11,979,880	10,757,777	9,535,675	8,313,572	7,091,469	5,869,366	4,647,263	3,425,160	2,203,058	2,203,058
50	**Net Capacity True-up Over/(Under) (Line 46+49)**	$8,812,368	$2,375,343	($2,764,247)	($4,615,483)	($3,966,112)	($7,299,099)	($8,066,548)	($8,778,934)	($3,410,661)	($229,841)	$267,075	($4,775,185)	($4,775,185)

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

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

		JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	Total
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	60,858,764
3	Orlando Cogen Limited (ORLACOGL)	5,102,804	5,102,804	5,102,804	5,102,804	5,089,383	5,094,138	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	61,211,555
4	Pasco County Resource Recovery (PASCOUNT)	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	21,417,600
5	Pinellas County Resource Recovery (PINCOUNT)	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	50,983,200
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,733,888	6,656,139	6,675,150	6,669,159	6,662,563	6,900,122	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	82,091,068
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	1,097,143	646,573	648,924	678,961	684,116	705,834	800,946	800,946	800,946	800,946	800,946	800,946	9,267,226
8	US EcoGen	-	-	-	(3,000)	(90,000)	(93,000)	-	-	-	-	-	-	(186,000)
9	Calpine Osprey	92,394	-	-	-	-	-	-	-	-	-	-	-	92,394
10	Subtotal - Base Level Capacity Costs	24,131,193	23,510,479	23,531,842	23,552,887	23,451,026	23,712,058	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	285,735,807
11	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
12	Base Level Jurisdictional Capacity Costs	22,414,258	21,837,709	21,857,551	21,877,099	21,782,485	22,024,945	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	265,405,704
13	**Intermediate Production Level Capacity Costs**													
14	Southern Franklin	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,260,918	6,260,918	4,623,002	2,712,100	2,712,100	3,531,058	49,572,645
15	Schedule H Capacity Sales - NSB & RCID	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Subtotal - Intermediate Level Capacity Costs	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,260,918	6,260,918	4,623,002	2,712,100	2,712,100	3,531,058	49,572,645
17	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
18	Intermediate Level Jurisdictional Capacity Costs	3,261,098	3,366,345	1,943,775	1,940,776	2,148,965	4,404,288	4,551,875	4,551,875	3,361,061	1,971,778	1,971,778	2,567,185	36,040,800
19	**Peaking Production Level Capacity Costs**													
20	Shady Hills	1,954,260	1,954,260	1,395,900	1,374,300	1,924,020	3,912,300	3,856,015	3,856,015	1,799,474	1,354,816	1,354,816	1,955,104	26,691,280
21	Vandolah (NSG)	2,924,309	2,889,528	1,965,274	1,943,845	2,795,467	5,785,430	5,539,623	5,495,150	2,629,977	1,937,310	1,981,783	2,788,227	38,675,923
22	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Subtotal - Peaking Level Capacity Costs	4,878,569	4,843,788	3,361,174	3,318,145	4,719,487	9,697,730	9,395,638	9,351,165	4,429,451	3,292,126	3,336,599	4,743,331	65,367,203
24	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
25	Peaking Level Jurisdictional Capacity Costs	4,679,718	4,646,355	3,224,173	3,182,897	4,527,121	9,302,450	9,012,672	8,970,012	4,248,907	3,157,939	3,200,600	4,549,993	62,702,836
26	**Other Capacity Costs**													
27	Retail Wheeling	(23,615)	(2,605)	(13,552)	(1,023)	(49,903)	(27)	(24,689)	(20,202)	(4,376)	(2,342)	(12,596)	(17,124)	(172,054)
28	RRSSA Second Amendment [1]													
29	Batch-19 Nuclear Fuel [2]													
30	ASC Servicing Fees [3]							(296,269)						(296,269)
31	Total Other Capacity Costs	1,768,743	1,785,790	1,770,879	1,779,445	1,726,601	1,772,514	1,447,620	1,744,413	1,756,275	1,754,346	1,740,128	1,674,699	20,721,452
32	**Total Capacity Costs (Line 12+18+25+31)**	32,123,817	31,636,198	28,796,378	28,780,217	30,185,172	37,504,198	37,280,776	37,534,909	31,634,852	29,152,673	29,181,116	31,060,484	384,870,792
33	**Nuclear Cost Recovery Clause**													
34	CR3 Uprate Costs	4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
35	**Total Recoverable Nuclear Costs**	4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
36														
37	**ISFSI Revenue Requirement** [4]	-	-	-	-	-	-	697,042	710,787	766,141	770,260	771,297	772,653	4,488,180
38	**Total Recov Capacity & Nuclear Costs (Line 32+35+37)**	36,583,010	36,067,967	33,200,724	33,157,137	34,534,669	41,826,271	42,272,467	42,512,921	36,640,795	34,135,309	34,137,366	35,990,667	441,059,303
39	**Capacity Revenues**													
40	Capacity Cost Recovery Revenues (net of tax)	28,519,282	29,627,699	28,061,262	31,308,667	35,187,257	38,498,070	41,005,606	42,944,849	41,950,646	38,649,455	32,526,800	30,799,664	419,079,255
41	Prior Period True-Up Provision Over/(Under) Recovery	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	14,665,234
42	**Current Period Revenues (net of tax)**	29,741,384	30,849,802	29,283,365	32,530,770	36,409,359	39,720,172	42,227,709	44,166,952	43,172,749	39,871,557	33,748,903	32,021,766	433,744,489
43	**True-Up Provision**													
44	True-Up Provision - Over/(Under) Recov (Line 42-38)	(6,841,625)	(5,218,166)	(3,917,359)	(626,366)	1,874,691	(2,106,099)	(44,758)	1,654,030	6,531,954	5,736,248	(388,463)	(3,968,902)	(7,314,815)
45	Interest Provision for the Month	7,805	3,244	(128)	(2,766)	(3,217)	(4,786)	(3,641)	(3,459)	(1,203)	715	31	(2,176)	(9,582)
46	Current Cycle Balance - Over/(Under)	(6,833,820)	(12,048,743)	(15,966,230)	(16,595,363)	(14,723,889)	(16,834,773)	(16,883,172)	(15,232,600)	(8,701,850)	(2,964,887)	(3,353,319)	(7,324,397)	(7,324,397)
47	Prior Period Balance - Over/(Under) Recovered	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292
48	Prior Period Cumulative True-Up Collected/(Refunded)	(1,222,103)	(2,444,206)	(3,666,309)	(4,888,411)	(6,110,514)	(7,332,617)	(8,554,720)	(9,776,823)	(10,998,926)	(12,221,028)	(13,443,131)	(14,665,234)	(14,665,234)
49	Prior Period True-up Balance - Over/(Under)	15,646,189	14,424,086	13,201,983	11,979,880	10,757,777	9,535,675	8,313,572	7,091,469	5,869,366	4,647,263	3,425,160	2,203,058	2,203,058
50	**Net Capacity True-up Over/(Under) (Line 46+49)**	8,812,368	2,375,343	(2,764,247)	(4,615,482)	(3,966,111)	(7,299,099)	(8,569,600)	(8,141,131)	(2,832,483)	1,682,376	71,841	(5,121,339)	(5,121,339)

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

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER

DECEMBER 2018

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

*Line 15a. MWH Data for Infomational Purposes Only

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 4
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: Christopher Menendez CAM-3T

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

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

*Line 15a. MWH Data for Infomational Purposes Only

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

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

FOOTNOTE: DETAIL OF LINE 6b ABOVE

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

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

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

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

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

N O T

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

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

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

A-3 Generating System Comparative Data Report

Docket No. 20190001-EI
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Exhibit No. (CAM-3T)
Schedule: A3-1
Sheet 6 of 9

Duke Energy Florida, LLC

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

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No. 20190001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule: A3-1
Sheet 7 of 9

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

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

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

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

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

	Counterparty	Type	MW	Start Date - End Date	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
1	Orange Cogen (ORANGECO)	QF	74.00	7/1/95 - 12/31/24	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	60,858,765
2	Orlando Cogen Limited (ORLACOGL)	QF	79.20	9/1/93 - 12/31/23	5,102,804	5,102,804	5,102,804	5,102,804	5,089,383	5,094,138	5,096,530	5,099,746	5,097,899	4,988,662	5,015,745	5,023,523	60,916,840
3	Pasco County Resource Recovery (PASCOUNT)	QF	23.00	1/1/95 - 12/31/24	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	21,417,600
4	Pinellas County Resource Recovery (PINCOUNT)	QF	54.75	1/1/95 - 12/31/24	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	50,983,200
5	Polk Power Partners, L.P. (MULBERRY)	QF	115.00	8/1/94 - 8/8/24	6,733,888	6,656,139	6,675,150	6,669,159	6,662,563	6,900,122	6,965,675	6,965,675	6,965,675	6,965,675	6,965,675	6,965,675	82,091,070
6	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	QF	39.60	8/1/94 - 12/31/23	1,097,143	646,573	648,924	678,961	684,116	705,834	719,623	750,224	765,134	751,969	754,931	755,868	8,959,300
7	Southern purchase - Franklin	Other	425	6/1/16 - 5/31/21	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,236,165	6,252,703	4,638,320	2,750,085	2,698,716	3,488,522	49,537,060
8	Retail Wheeling				(23,615)	(2,605)	(13,552)	(1,023)	(49,903)	(27)	(9,282)	(6,007)	(3,342)	(4,243)	0	(1,766)	(115,365)
9	CR-3 Projected Expense				4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
10	ISFSI Return				0	0	0	0	0	0	724,926	726,807	728,105	735,486	747,111	751,681	4,414,116
11	ASC Servicing Fee				0	0	0	0	0	0	(296,269)	0	(160,182)	0	0	0	(456,451)
	SUBTOTAL				32,959,883	32,569,913	30,596,218	30,601,242	30,796,432	34,185,023	34,836,981	35,161,337	33,376,374	31,504,974	31,472,095	32,245,996	390,306,468
	Confidential Capacity Contracts (Aggregated):																
	Purchases/Sales (Net)		MW	Contracts													
	Vandolah Capacity - Northern Star			6/1/12-5/31/27	2,924,309	2,889,528	1,965,274	1,943,845	2,795,467	5,785,430	5,768,280	5,707,232	2,712,726	1,918,109	2,015,348	2,943,834	39,369,382
	Schedule H Capacity Sales-City of Tallahassee		-1	on-going no term date	0	0	0	0	0	0	(73,253)	0	0	(75,671)	(6,305)	(37,835)	(193,065)
	Shady Hills Tolling		517	4/1/07-4/30/24	1,954,260	1,954,260	1,395,900	1,374,300	1,924,020	3,912,300	3,912,300	3,912,300	1,825,740	1,149,734	1,374,300	1,984,500	26,673,914
	EcoGen				0	0	0	(3,000)	(90,000)	(93,000)	(90,000)	(93,000)	(93,000)	(90,000)	(93,000)	(90,000)	(735,000)
	Calpine Osprey		515	Oct-14 to Jan-17	92,394	0	0	0	0	0	0	0	0	0	0	0	92,394
	RRSSA Second Amendment [1]																
	Batch-19 Nuclear Fuel [2]																
			1031														
	Total				39,723,203	39,202,095	35,741,824	35,696,855	37,202,424	45,562,294	46,122,885	46,452,483	39,582,491	36,163,833	36,401,286	38,681,380	476,533,054

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

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

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

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

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 5
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: Christopher Menendez CAM-4T

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

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

Total Debt	1.97%	1.97%
Total Equity	4.65%	6.23%

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

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

Docket No. 20190001-EI
Exhibit No. ____(CAM-2)
Part 1

Duke Energy Florida, LLC

Fuel Cost Recovery

Actual / Estimated True-Up

January through December 2019

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-12-0425-PAA-EU)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 6
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: Christopher Menendez CAM-2

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

			Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	6 Month Sub-Total
A	1	Fuel Cost of System Generation	$ 109,976,964	$ 82,327,645	$ 91,917,642	$ 96,277,004	$ 109,917,691	$ 118,976,978	$ 609,393,924
	2	Fuel Cost of Power Sold	(3,100,010)	(1,478,546)	(2,257,015)	(2,883,465)	(4,252,385)	(9,623,682)	(23,595,103)
	3	Fuel Cost of Purchased Power	3,709,959	2,648,955	5,132,188	6,247,340	13,339,364	12,829,894	43,907,699
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	10,908,157	7,601,725	7,328,667	7,064,641	8,882,702	9,231,306	51,017,197
	4	Energy Cost of Economy Purchases	184,282	240,158	250,203	378,398	462,113	517,405	2,032,557
	5	Adjustments to Fuel Cost	1,304,334	1,209,489	1,202,751	1,198,907	1,197,017	1,196,947	7,309,445
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	122,983,686	92,549,425	103,574,435	108,282,824	129,546,501	133,128,847	690,065,719
B	1	Jurisdictional mWh Sales	2,669,994	2,719,125	2,780,959	2,897,129	3,185,818	3,813,849	18,066,873
	2	Non-Jurisdictional mWh Sales	19,604	18,678	12,252	12,171	17,654	31,506	111,863
	3	TOTAL SALES (Lines B1 + B2)	2,689,597	2,737,803	2,793,210	2,909,299	3,203,472	3,845,354	18,178,736
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.32%	99.56%	99.58%	99.45%	99.18%	99.38%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	104,760,834	106,246,246	108,046,001	112,815,219	125,936,532	152,625,203	710,430,035
	2	True-Up Provision	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(74,225,460)
	2a	Incentive Provision	191,794	191,794	191,794	191,794	191,794	191,794	1,150,764
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	92,581,718	94,067,130	95,866,885	100,636,103	113,757,416	140,446,087	637,355,339
	4	Fuel & Net Power Transactions (Line A6)	122,983,686	92,549,425	103,574,435	108,282,824	129,546,501	133,128,847	690,065,719
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	122,123,752	91,951,342	103,153,768	107,864,698	128,877,798	132,082,083	686,053,442
	6	Over/(Under) Recovery (Line C3 - Line C5)	(29,542,034)	2,115,788	(7,286,883)	(7,228,595)	(15,120,383)	8,364,004	(48,698,103)
	7	Interest Provision	(422,930)	(428,593)	(415,902)	(408,311)	(398,760)	(371,997)	(2,446,493)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(29,964,965)	1,687,195	(7,702,785)	(7,636,906)	(15,519,143)	7,992,008	(51,144,593)
	9	Plus: Prior Period Balance	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)
	10	Plus: Cumulative True-Up Provision	12,370,910	24,741,820	37,112,730	49,483,640	61,854,550	74,225,460	74,225,460
	11	Subtotal Prior Period True-up	(190,508,680)	(178,137,770)	(165,766,860)	(153,395,950)	(141,025,040)	(128,654,130)	(128,654,130)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($220,473,645)	(206,415,539)	($201,747,415)	($197,013,411)	($200,161,644)	($179,798,727)	(179,798,727)

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

			Jul Estimated	Aug Estimated	Sep Estimated	Oct Estimated	Nov Estimated	Dec Estimated	12 Month Period
A	1	Fuel Cost of System Generation	$ 117,430,448	$ 116,590,525	$ 108,507,217	$ 95,523,571	$ 87,935,869	$ 92,653,910	$ 1,228,035,464
	2	Fuel Cost of Power Sold	(8,107,008)	(8,047,357)	(6,900,753)	(6,494,023)	(3,667,686)	(4,267,921)	(61,079,851)
	3	Fuel Cost of Purchased Power	8,184,838	6,876,582	6,779,581	7,136,160	2,844,662	1,106,770	76,836,292
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	10,332,497	10,289,444	9,155,724	9,742,112	9,860,682	10,026,097	110,423,752
	4	Energy Cost of Economy Purchases	188,238	123,884	128,246	137,662	89,384	223,111	2,923,082
	5	Adjustments to Fuel Cost	1,185,271	1,181,837	1,172,013	1,168,362	1,164,477	1,162,111	14,343,516
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	129,214,284	127,014,915	118,842,028	107,213,844	98,227,388	100,904,077	1,371,482,256
B	1	Jurisdictional mWh Sales	3,840,042	3,872,711	3,972,711	3,626,916	3,055,736	2,878,978	39,313,967
	2	Non-Jurisdictional mWh Sales	36,625	37,341	16,716	14,981	11,631	13,906	243,064
	3	TOTAL SALES (Lines B1 + B2)	3,876,667	3,910,052	3,989,428	3,641,897	3,067,367	2,892,884	39,557,031
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.06%	99.05%	99.58%	99.59%	99.62%	99 52%	99.39%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	152,301,622	153,597,318	157,563,471	143,848,708	121,194,902	114,184,412	1,553,120,468
	2	True-Up Provision	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(148,450,915)
	2a	Incentive Provision	191,794	191,794	191,794	191,794	191,794	191,792	2,301,526
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	140,122,506	141,418,202	145,384,355	131,669,592	109,015,786	102,005,294	1,406,971,079
	4	Fuel & Net Power Transactions (Line A6)	129,214,284	127,014,915	118,842,028	107,213,844	98,227,388	100,904,077	1,371,482,256
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	128,043,189	125,851,048	118,383,128	106,810,571	97,887,395	100,453,881	1,363,482,653
	6	Over/(Under) Recovery (Line C3 - Line C5)	12,079,317	15,567,153	27,001,228	24,859,021	11,128,391	1,551,413	43,488,421
	7	Interest Provision	(328,337)	(277,639)	(212,216)	(137,572)	(78,343)	(41,829)	(3,522,429)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	11,750,980	15,289,514	26,789,011	24,721,449	11,050,048	1,509,584	39,965,991
	9	Plus: Prior Period Balance	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)
	10	Plus: Cumulative True-Up Provision	86,596,370	98,967,280	111,338,190	123,709,100	136,080,010	148,450,915	148,450,915
	11	Subtotal Prior Period True-up	(116,283,220)	(103,912,310)	(91,541,400)	(79,170,490)	(66,799,580)	(54,428,675)	(54,428,675)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($155,676,837)	($128,016,412)	($88,856,491)	($51,764,131)	($28,343,173)	($14,462,684)	(14,462,684)

Duke Energy Florida, LLC
Comparison of Actual/Es imated Vs. Original Projections
of the Fuel and Purchased Power Cost Recovery Factor
Estimated for the Period of : January 2019 through December 2019

		DOLLARS				mWh				c/kWh			
		Actual/ Estimated	Projection Filing	Difference Amount	Difference %	Actual/ Estimated	Projection Filing	Difference Amount	Difference %	Actual/ Estimated	Projection Filing	Difference Amount	Difference %
1	Fuel Cost of System Net Generation (E3)	1,228,035,464	1,281,071,130	(53,035,666)	-4%	40,089,304	39,800,289	289,016	1%	3.063	3.219	-0.155	-5%
2	Coal Car Investment	-	-	-	0%			-	0%	0.000	0.000	0 000	0%
3	Adjustment to Fuel Cost	14,343,516	14,290,753	52,763	0%			-	0%	0.000	0.000	0 000	0%
4	TOTAL COST OF GENERATED POWER	1,242,378,980	1,295,361,883	(52,982,903)	-4%	40,089,304	39,800,289	289,016	1%	3.099	3.255	-0.156	-5%
5	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)	76,836,292	24,127,178	52,709,114	218%	1,967,131	696,167	1,270,963	183%	3.906	3.466	0.440	13%
6	Energy Cost of Economy Purchases (E9)	2,923,082	2,366,773	556,309	24%	74,548	57,825	16,723	29%	3.921	4.093	-0.172	-4%
7	Payments to Qualifying Facilities (E8)	110,423,752	130,146,818	(19,723,066)	-15%	2,724,789	3,080,184	(355,394)	-12%	4.053	4.225	-0.173	-4%
8	TOTAL COST OF PURCHASED POWER	190,183,126	156,640,769	33,542,357	21%	4,766,468	3,834,176	932,292	24%	3.990	4.085	-0 095	-2%
9	TOTAL AVAILABLE mWh (LINE 4 + LINE 8)			-		44,855,772	43,634,464	1,221,308	3%	0.000	0.000	0 000	0%
10	Fuel Cost of Economy Sales (E6)	(4,834,701)	(6,284,266)	1,449,565	-23%	(141,389)	(177,337)	35,948	-20%	3.419	3.544	-0.124	-4%
10a	Gain on Economy Sales (E6)	(1,656,431)	(1,748,022)	91,591	-5%	(141,389)	(177,337)	35,948	-20%	1.172	0.986	0.186	19%
10b	Gain on Total Power Sales - 20% (E6)	64,544	88,904	(24,360)	100%			-	0%	0.000	0.000	0 000	0%
11	Fuel Cost of Stratified Sales (E6)	(54,653,263)	(24,433,112)	(30,220,151)	124%	(2,453,803)	(1,327,455)	(1,126,348)	85%	2.227	1.841	0 387	21%
12	TOTAL FUEL COST AND GAINS OF POWER SALES (LINES 10 + 10a + 10b + 11)	(61,079,851)	(32,376,496)	(28,703,355)	89%	(2,595,192)	(1,504,792)	(1,090,400)	72%	2.354	2.152	0 202	9%
13	Net Inadvertent Interchange					107,645		107,645					
14	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 4 + 8 + 12 + 13)	1,371,482,256	1,419,626,156	(48,143,900)	-3%	42,368,225	42,129,673	238,552	1%	3.237	3.370	-0.133	-4%
15	Net Unbilled					161,728	(128,821)	290,549	-226%	0.000	0.000	0 000	0%
16	Company Use					(199,795)	(174,656)	(25,139)	14%	0.000	0.000	0 000	0%
17	T & D Losses					(2,773,127)	(2,317,616)	(455,511)	20%	0.000	0.000	0 000	0%
18	SYSTEM mWh SALES	1,371,482,256	1,419,626,156	(48,143,900)	-3%	39,557,031	39,508,579	48,452	0%	3.467	3.593	-0.126	-4%
19	Wholesale mWh Sales	(8,459,368)	(7,650,122)	(809,245)	11%	(243,064)	(212,147)	(30,916)	15%	3.480	3.606	-0.126	-3%
20	Jurisdictional mWh Sales	1,363,022,888	1,411,976,034	(48,953,145)	-3%	39,313,967	39,296,432	17,535	0%	3.467	3.593	-0.126	-4%
20a	Jurisdictional Loss Multiplier	1 00034	1.00031	0.00003	0%	1.00034	1.00031	3E-05	0%				
21	Jurisdictional Sales Adjusted for Line Losses	1,363,482,653	1,412,413,746	(48,931,093)	-3%	39,313,967	39,296,432	17,535	0%	3.468	3.594	-0.126	-4%
22	TRUE-UP	202,879,590	148,450,915	54,428,675	37%	39,313,967	39,296,432	17,535	0%	0.516	0.378	0.138	37%
23	TOTAL JURISDICTIONAL FUEL COST	1,566,362,249	1,560,864,661	5,497,588	0%	39,313,967	39,296,432	17,535	0%	3.984	3.972	0 012	0%
24	Revenue Tax Factor	1,127,781	1,123,823	3,958	0%								
25	Fuel Factor Adjusted for Taxes	1,567,490,030	1,561,988,484	5,501,546	0%	39,313,967	39,296,432	17,535	0%	3.987	3.975	0 012	0%
26	GPIF **	(2,301,526)	(2,301,526)	-	0%	39,313,967	39,296,432	17,535	0%	(0.006)	(0.006)	0 000	0%
27	Fuel Factor Adjusted for Taxes Including GPIF	1,565,188,504	1,559,686,958	5,501,546	0%	39,313,967	39,296,432	17,535	0%	3.981	3.969	0 012	0%
28	FUEL FACTOR ROUNDED TO NEAREST .001 c/kWh									3.981	3.969	0 012	0%

Docket No. 20190001-EI
Exhibit CAM-2, Part 1
Schedule E2

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2019 through December 2019

			Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	TOTAL
1	Fuel Cost of System Net Generation		$109,976,964	$82,327,645	$91,917,642	$96,277,004	$109,917,691	$118,976,978	$117,430,448	$116,590,525	$108,507,217	$95,523,571	$87,935,869	$92,653,910	$1,228,035,464
1a	Adjustments to Fuel Cost		1,304,334	1,209,489	1,202,751	1,198,907	1,197,017	1,196,947	1,185,271	1,181,837	1,172,013	1,168,362	1,164,477	1,162,111	14,343,516
2	Fuel Cost of Power Sold		(686,538)	(37,098)	(264,257)	(499,381)	(594,272)	(471,077)	(550,381)	(806,661)	(414,607)	(157,883)	(138,100)	(214,445)	(4,834,701)
2a	Gains on Power Sales		(292,981)	58,390	(125,420)	(159,460)	(343,905)	(189,077)	(145,665)	(213,493)	(109,730)	(41,786)	(36,550)	(56,756)	(1,656,431)
2b	Gain on Total Power Sales - 20%		0	0	0	0	0	0	0	15,580	21,946	8,357	7,310	11,351	64,544
2c	Fuel Cost of Stratified Sales		(2,120,491)	(1,499,837)	(1,867,338)	(2,224,625)	(3,314,209)	(8,963,528)	(7,410,962)	(7,042,783)	(6,398,362)	(6,302,711)	(3,500,346)	(4,008,072)	(54,653,263)
3	Fuel Cost of Purchased Power (Excl Economy)		3,709,959	2,648,955	5,132,188	6,247,340	13,339,364	12,829,894	8,184,838	6,876,582	6,779,581	7,136,160	2,844,662	1,106,770	76,836,292
3a	Energy Payments to Qualifying Facilities		10,908,157	7,601,725	7,328,667	7,064,641	8,882,702	9,231,306	10,332,497	10,289,444	9,155,724	9,742,112	9,860,682	10,026,097	110,423,752
4	Energy Cost of Economy Purchases		184,282	240,158	250,203	378,398	462,113	517,405	188,238	123,884	128,246	137,662	89,384	223,111	2,923,082
5	Total System Fuel & Net Power Transactions		$122,983,686	$92,549,425	$103,574,435	$108,282,824	$129,546,501	$133,128,847	$129,214,284	$127,014,915	$118,842,028	$107,213,844	$98,227,388	$100,904,077	$1,371,482,256
6	Jurisdictional MWH Sold		2,669,994	2,719,125	2,780,959	2,897,129	3,185,818	3,813,849	3,840,042	3,872,711	3,972,711	3,626,916	3,055,736	2,878,978	39,313,967
7	Jurisdictional % of Total Sales		99.27%	99.32%	99.56%	99.58%	99.45%	99.18%	99.06%	99.05%	99.58%	99.59%	99.62%	99.52%	99.39%
8	Jurisdicitonal Fuel & Net Power Transactions		122,085,905	91,920,089	103,118,708	107,828,036	128,833,995	132,037,191	127,999,669	125,808,274	118,342,891	106,774,268	97,854,124	100,419,738	1,363,022,888
9	Jurisdictional Loss Multiplier		1.00031	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034
10	Jurisdictional Fuel & Net Power Transactions		122,123,752	91,951,342	103,153,768	107,864,698	128,877,798	132,082,083	128,043,189	125,851,048	118,383,128	106,810,571	97,887,395	100,453,881	1,363,482,653
11	Adjusted System Sales	MWH	2,689,597	2,737,803	2,793,210	2,909,299	3,203,472	3,845,354	3,876,667	3,910,052	3,989,428	3,641,897	3,067,367	2,892,884	39,557,031
12	System Cost per MWH Sold	c/kwh	4.5726	3.3804	3.7080	3.7220	4.0439	3.4621	3.3331	3.2484	2.9789	2.9439	3.2023	3.4880	3.4671
13	Jurisdictional Loss Multiplier	x	1.00031	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034
14	Jurisdictional Cost per MWH Sold	c/kwh	4.5739	3.3817	3.7093	3.7232	4.0454	3.4632	3.3344	3.2497	2.9799	2.9449	3.2034	3.4892	3.4682
15	Prior Period True-Up	+	0.6332	0.6218	0.6079	0.5836	0.5307	0.4433	0.4403	0.4366	0.4256	0.4661	0.5533	0.5872	0.5160
16	Total Jurisdictional Fuel Expense	c/kwh	5.2071	4.0034	4.3172	4.3067	4.5760	3.9065	3.7747	3.6862	3.4055	3.4111	3.7567	4.0765	3.9842
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	5.2109	4.0063	4.3203	4.3098	4.5793	3.9093	3.7774	3.6889	3.4079	3.4135	3.7594	4.0794	3.9871
19	GPIF	+	-0.0072	-0.0071	-0.0069	-0.0066	-0.0060	-0.0050	-0.0050	-0.0050	-0.0048	-0.0053	-0.0063	-0.0067	-0.0059
20	Total Recovery Factor (rounded .001)	c/kwh	5.204	3.999	4.313	4.303	4.573	3.904	3.772	3.684	3.403	3.408	3.753	4.073	3.981

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2019 through December 2019

			Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		1,280,215	500,019	923,169	692,111	558,241	1,564,207	5,517,961
2	COAL		9,717,146	1,268,395	11,151,969	12,160,194	13,253,021	19,050,460	66,601,186
3	GAS		98,979,603	80,559,232	79,842,503	83,424,699	96,106,429	98,362,310	537,274,776
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	109,976,964	82,327,645	91,917,642	96,277,004	109,917,691	118,976,978	609,393,924
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		4,763	2,044	1,765	2,799	1,130	6,148	18,649
7	COAL		264,871	30,218	322,808	317,703	343,517	471,976	1,751,093
8	GAS		2,633,224	2,464,229	2,380,552	2,695,261	3,238,581	3,475,245	16,887,092
9	SOLAR		10,136	11,844	19,147	21,071	24,406	19,739	106,343
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	2,912,994	2,508,335	2,724,272	3,036,835	3,607,634	3,973,108	18,763,177
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	10,171	4,468	8,488	6,246	4,508	13,155	47,036
13	COAL	TON	129,315	17,108	143,944	145,073	156,909	223,183	815,532
14	GAS	MCF	19,200,944	17,922,366	17,286,942	19,557,528	24,285,821	26,151,841	124,405,442
15	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		58,098	25,716	48,952	36,010	25,914	75,863	270,553
17	COAL		2,898,520	381,337	3,208,512	3,267,044	3,552,106	5,060,005	18,367,524
18	GAS		19,574,700	18,251,784	17,589,544	19,931,814	24,777,295	26,767,772	126,892,909
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	22,531,317	18,658,838	20,847,008	23,234,868	28,355,314	31,903,641	145,530,986
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.16%	0.08%	0.07%	0.09%	0.03%	0.16%	0.10%
22	COAL		9.09%	1.21%	11.85%	10.46%	9.52%	11.88%	9.33%
23	GAS		90.40%	98.24%	87.38%	88.75%	89.77%	87.47%	90.00%
24	SOLAR		0.35%	0.47%	0.70%	0.69%	0.68%	0.50%	0.57%
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	125.87	111.91	108.76	110.81	123.83	118.91	117.31
28	COAL	$/TON	75.14	74.14	77.47	83.82	84.46	85.36	81.67
29	GAS	$/MCF	5.15	4.49	4.62	4.27	3.96	3.76	4.32
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		22.04	19.44	18.86	19.22	21.54	20.62	20.40
32	COAL		3.35	3.33	3.48	3.72	3.73	3.77	3.63
33	GAS		5.06	4.41	4.54	4.19	3.88	3.68	4.23
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	4.88	4.41	4.41	4.14	3.88	3.73	4.19
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		12,198	12,582	27,743	12,865	22,924	12,339	14,507
37	COAL		10,943	12,620	9,939	10,283	10,340	10,721	10,489
38	GAS		7,434	7,407	7,389	7,395	7,651	7,702	7,514
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,735	7,439	7,652	7,651	7,860	8,030	7,756
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		26.88	24.46	52.32	24.73	49.38	25.44	29.59
42	COAL		3.67	4.20	3.45	3.83	3.86	4.04	3.80
43	GAS		3.76	3.27	3.35	3.10	2.97	2.83	3.18
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	3.78	3.28	3.37	3.17	3.05	2.99	3.25

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2019 through December 2019

			Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		178,715	158,732	125,827	168,075	170,774	86,001	6,406,085
2	COAL		19,789,982	18,055,094	15,456,479	10,938,395	14,291,134	3,171,138	148,303,408
3	GAS		97,461,751	98,376,699	92,924,911	84,417,101	73,473,961	89,396,771	1,073,325,970
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	117,430,448	116,590,525	108,507,217	95,523,571	87,935,869	92,653,910	1,228,035,464
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		97	24	0	12	0	0	18,782
7	COAL		481,372	436,788	363,514	233,800	343,478	0	3,610,045
8	GAS		3,651,204	3,676,118	3,479,716	3,070,001	2,379,112	3,091,140	36,234,382
9	SOLAR		21,401	20,792	18,958	18,693	15,320	24,589	226,096
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	4,154,073	4,133,722	3,862,188	3,322,506	2,737,910	3,115,729	40,089,304
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	1,170	915	498	1,028	1,069	0	51,716
13	COAL	TON	223,375	201,849	167,037	106,143	152,634	0	1,666,570
14	GAS	MCF	26,867,149	27,179,166	25,656,038	22,808,534	17,499,286	21,672,586	266,088,201
15	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		6,822	5,334	2,905	5,991	6,225	0	297,830
17	COAL		5,159,582	4,683,627	3,893,384	2,483,207	3,579,617	0	38,166,941
18	GAS		26,867,149	27,179,166	25,656,038	22,808,534	17,499,286	21,672,586	268,575,668
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	32,033,553	31,868,127	29,552,327	25,297,732	21,085,128	21,672,586	307,040,439
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%
22	COAL		11.59%	10.57%	9.41%	7.04%	12.55%	0.00%	9.01%
23	GAS		87.90%	88.93%	90.10%	92.40%	86.90%	99.21%	90.38%
24	SOLAR		0.52%	0.50%	0.49%	0.56%	0.56%	0.79%	0.56%
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	152.75	173.48	252.66	163.50	159.75	0.00	123.87
28	COAL	$/TON	88.60	89.45	92.53	103.05	93.63	0.00	88.99
29	GAS	$/MCF	3.63	3.62	3.62	3.70	4.20	4.12	4.03
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		26.20	29.76	43.31	28.06	27.43	0.00	21.51
32	COAL		3.84	3.86	3.97	4.41	3.99	0.00	3.89
33	GAS		3.63	3.62	3.62	3.70	4.20	4.13	4.00
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	3.67	3.66	3.67	3.78	4.17	4.28	4.00
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		70,330	222,250	0	499,250	0	0	15,857
37	COAL		10,718	10,723	10,710	10,621	10,422	0	10,572
38	GAS		7,358	7,393	7,373	7,429	7,355	7,011	7,412
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,711	7,709	7,652	7,614	7,701	6,956	7,659
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		184.24	661.38	0.00	1400.63	0.00	0.00	34.11
42	COAL		4.11	4.13	4.25	4.68	4.16	0.00	4.11
43	GAS		2.67	2.68	2.67	2.75	3.09	2.89	2.96
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	2.83	2.82	2.81	2.88	3.21	2.97	3.06

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-19

(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	293,751	53.9	96.61	55 6	10,752	COAL	136,739 TONS	23.10	3,158,435	11,764,391	4 00
2 CRYSTAL RIVER 5	712	187,621	35.4	93.98	56 3	10,666	COAL	86,636 TONS	23.10	2,001,147	8,025,591	4 28
3 ANCLOTE 1	517	108,958	28.3	94.19	30.1	11,130	GAS	1,212,678 MCF	1.00	1,212,678	3,890,738	3 57
4 ANCLOTE 2	521	41,416	10.7	99.03	31.7	11,884	GAS	492,174 MCF	1.00	492,174	2,161,528	5 22
5 AVON PARK 1-2	69	30	0.1	92.73	43 5	16,333	GAS	490 MCF	1.00	490	1,177	3 92
6 BARTOW 1-4	228	351	0.2	87.39	19 2	14,051	GAS	4,929 MCF	1.00	4,929	18,704	5 33
7 BARTOW CC 1	1279	621,891	65.4	94.84	68 9	7,666	GAS	4,767,673 MCF	1.00	4,767,673	17,102,315	2.75
8 CITRUS CC 1-2	1640	1,152,776	94.5	97.58	97 3	6,542	GAS	7,541,481 MCF	1.00	7,541,481	27,442,112	2 38
9 DEBARY 1-10	785	15,454	2.7	90.94	0.1	12,826	GAS	198,217 MCF	1.00	198,217	718,013	4 65
10 HIGGINS 1-4	129	199	0.2	65.24	19 3	15,496	GAS	3,079 MCF	1.00	3,079	13,747	6 92
11 HINES CC 1-4	2,204	1,243,506	75.8	97.42	79 2	7,222	GAS	8,980,744 MCF	1.00	8,980,744	32,669,731	2 63
12 INT CITY 1-14	1,186	17,020	1 9	93.74	6 6	12,818	GAS	218,157 MCF	1.00	218,157	805,838	4.73
13 OSPREY CC 1	505	297,355	79.1	94.67	86 0	7,494	GAS	2,228,334 MCF	1.00	2,228,334	8,116,722	2.73
14 SUWANNEE CT 1-3	200	3,833	2.6	86 86	24.7	13,544	GAS	51,913 MCF	1.00	51,913	190,639	4 97
15 TIGER BAY CC 1	225	116,946	69.9	95.81	88.7	7,460	GAS	872,435 MCF	1.00	872,435	3,227,285	2.76
16 UNIV OF FLA. CC 1	47	31,469	90.0	96.14	93 6	9,369	GAS	294,845 MCF	1.00	294,845	1,103,202	3 51
17 AVON PARK 1-2	69	0	0.0	92.73	0 0	0	LIGHT O L	0 BBLS		0	0	0 00
18 BARTOW 1-4	228	0	0 0	87.39	0 0	0	LIGHT O L	0 BBLS		0	0	0 00
19 BAYBORO 1-4	231	4	0.0	91.94	0 0	13,902	LIGHT O L	10 BBLS	5.70	57	770	18.78
20 DEBARY 1-10	785	29	2.7	90.94	3.7	17,716	LIGHT O L	87 BBLS	5.89	512	9,069	31 38
21 HIGGINS 1-4	129	0	0.0	65.24	0 0	0	LIGHT O L	0 BBLS		0	0	0 00
22 OTHER	0	0	0.0	97.42	0 0	0	LIGHT O L	0 BBLS		0	0	0.00
23 INT CITY 1-14	1,186	44	1 9	93.74	3.7	13,682	LIGHT O L	103 BBLS	5.84	602	12,999	29 54
24 SUWANNEE 1-3	200	20	2.6	86.86	0 0	12,800	LIGHT O L	44 BBLS	5.82	256	5,038	25.19
25 OTHER & START UP	-	0	-	97.42	0 0	0	LIGHT O L	926 BBLS	5.83	5,395	150,839	0 00
26 SOLAR	92	21,401	31 3	93.74	57.7	0	SOLAR	0 N/A		0	0	0 00
27 TOTAL		4,154,073								32,033,553	117,430,448	2 83

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-19

	(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	170,111	31.2	85 68	54.4	10,783	COAL	79,049 TONS	23.20	1,834,222	7,409,068	4 36
2	CRYSTAL RIVER 5	712	266,677	50.3	90 05	55.7	10,685	COAL	122,800 TONS	23.20	2,849,405	10,646,026	3 99
3	ANCLOTE 1	517	115,101	29.9	97.10	30.8	11,087	GAS	1,276,110 MCF	1.00	1,276,110	4,202,060	3 65
4	ANCLOTE 2	521	64,285	16.6	99 03	29.8	11,932	GAS	767,047 MCF	1.00	767,047	2,984,890	4 64
5	AVON PARK 1-2	69	15	0.0	92 86	21.7	16,733	GAS	251 MCF	1.00	251	601	4 01
6	BARTOW 1-4	228	161	0.1	84 98	23.5	14,077	GAS	2,265 MCF	1.00	2,265	10,398	6.46
7	BARTOW CC 1	1279	636,669	66.9	97.42	68.8	7,661	GAS	4,877,251 MCF	1.00	4,877,251	17,487,528	2.75
8	CITRUS CC 1-2	1640	1,129,744	92.6	95 65	97.4	6,531	GAS	7,377,820 MCF	1.00	7,377,820	26,807,910	2 37
9	DEBARY 1-10	785	15,199	2.6	91.77	10.0	12,818	GAS	194,829 MCF	1.00	194,829	725,394	4.77
10	HIGGINS 1-4	129	216	0.2	65 02	20.9	15,530	GAS	3,353 MCF	1.00	3,353	13,887	6.43
11	H NES CC 1-4	2,204	1,250,481	76.3	97 66	78.9	7,222	GAS	9,031,542 MCF	1.00	9,031,542	32,799,483	2 62
12	INT CITY 1-14	1,186	16,496	1.9	94.20	6.6	12,816	GAS	211,401 MCF	1.00	211,401	802,611	4 87
13	OSPREY CC 1	505	295,530	78.7	94 80	85.6	7,496	GAS	2,215,272 MCF	1.00	2,215,272	8,056,483	2.73
14	SUWANNEE CT 1-3	200	3,918	2.6	88 08	24.8	13,544	GAS	53,065 MCF	1.00	53,065	196,443	5 01
15	TIGER BAY CC 1	225	116,095	69.4	95.16	88.8	7,471	GAS	867,360 MCF	1.00	867,360	3,162,452	2.72
16	UNIV OF FLA. CC 1	47	32,208	92.1	98 35	93.6	9,364	GAS	301,600 MCF	1.00	301,600	1,126,559	3 50
17	AVON PARK 1-2	69	0	0.0	92 86	0.0	0	LIGHT O L	0 BBLS		0	0	0 00
18	BARTOW 1-4	228	0	0.0	84.98	0.0	0	LIGHT O L	0 BBLS		0	0	0 00
19	BAYBORO 1-4	231	0	0.0	89.10	0.0	0	LIGHT O L	0 BBLS		0	0	0 00
20	DEBARY 1-10	785	0	0.0	91.77	0.0	0	LIGHT O L	0 BBLS		0	2,082	0 00
21	HIGGINS 1-4	129	0	0.0	65 02	0.0	0	LIGHT O L	0 BBLS		0	0	0 00
22	OTHER	0	0	0.0	0 00	0.0	0	LIGHT O L	0 BBLS		0	0	0 00
23	INT CITY 1-14	1,186	24	1.9	94.20	0 0	14,750	LIGHT O L	61 BBLS	5.80	354	9,680	40 33
24	SUWANNEE 1-3	200	0	0.0	88 08	0.0	0	LIGHT O L	0 BBLS		0	1,508	0 00
25	OTHER & START UP	-	0	-	97 66	0.0	0	LIGHT O L	854 BBLS	5.83	4,980	145,462	0 00
26	SOLAR	92	20,792	30.4	94.20	56.2	0	SOLAR	0 N/A		0	0	0 00
27	TOTAL		4,133,722								31,868,127	116,590,525	2 82

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-19

(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	91,187	17.3	90.31	53.9	10,793	COAL	42,224 TONS	23 31	984,174	4,691,071	5.14
2 CRYSTAL RIVER 5	712	272,327	53.1	94.75	55.9	10,683	COAL	124,813 TONS	23 31	2,909,210	10,765,408	3.95
3 ANCLOTE 1	517	106,720	28.7	94.00	30.5	11,112	GAS	1,185,910 MCF	1 00	1,185,910	3,999,240	3.75
4 ANCLOTE 2	521	47,309	12.6	98.00	31.7	11,889	GAS	562,466 MCF	1 00	562,466	2,526,042	5.34
5 AVON PARK 1-2	69	5	0.0	93.93	0.0	16,800	GAS	84 MCF	1 00	84	198	3.96
6 BARTOW 1-4	228	152	0.1	83.82	16.6	14,165	GAS	2,146 MCF	1 00	2,146	6,471	4.27
7 BARTOW CC 1	1279	579,806	63.0	94.67	66.5	7,666	GAS	4,444,568 MCF	1 00	4,444,568	15,803,774	2.73
8 CITRUS CC 1-2	1640	1,097,574	93.0	96.00	97.1	6,528	GAS	7,164,433 MCF	1 00	7,164,433	25,957,560	2.36
9 DEBARY 1-10	785	15,508	2.7	91.09	10.0	12,838	GAS	199,090 MCF	1 00	199,090	703,709	4.54
10 HIGG NS 1-4	129	176	0.2	62.80	22.7	15,792	GAS	2,773 MCF	1 00	2,773	9,948	5.67
11 HINES CC 1-4	2,204	1,180,064	74.4	96.17	78.2	7,234	GAS	8,536,028 MCF	1 00	8,536,028	30,996,186	2.63
12 INT CITY 1-14	1,186	16,628	1.9	93.50	6.5	12,837	GAS	213,455 MCF	1 00	213,455	749,590	4.51
13 OSPREY CC 1	505	286,635	78.8	94.60	85.2	7,496	GAS	2,148,492 MCF	1 00	2,148,492	7,785,787	2.72
14 SUWANNEE CT 1-3	200	3,946	2.7	88.32	25.0	13,567	GAS	53,532 MCF	1 00	53,532	193,298	4.90
15 TIGER BAY CC 1	225	114,571	70.7	93.67	88.7	7,473	GAS	856,155 MCF	1 00	856,155	3,124,520	2.73
16 UNIV OF FLA. CC 1	47	30,624	90.5	96.62	93.6	9,369	GAS	286,906 MCF	1 00	286,906	1,068,588	3.49
17 AVON PARK 1-2	69	0	0.0	93.93	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
18 BARTOW 1-4	228	0	0.0	83.82	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
19 BAYBORO 1-4	231	0	0.0	88.02	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
20 DEBARY 1-10	785	0	0.0	91.09	0.0	0	LIGHT OIL	0 BBLS		0	2,082	0.00
21 HIGG NS 1-4	129	0	0.0	62.80	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
22 OTHER	0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
23 INT CITY 1-14	1,186	0	0.0	93.50	0.0	0	LIGHT OIL	0 BBLS		0	4,907	0.00
24 SUWANNEE 1-3	200	0	0.0	88.32	0.0	0	LIGHT OIL	0 BBLS		0	1,508	0.00
25 OTHER & START UP	-	0	-	96.17	0.0	0	LIGHT OIL	498 BBLS	5 83	2,905	117,330	0.00
26 SOLAR	92	18,958	28.6	93.50	56.0	0	SOLAR	0 N/A		0	0	0.00
27 TOTAL		3,862,188								29,552,327	108,507,217	2.81

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-19

	(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	39,230	7.2	90.70	61.6	10,618	COAL	17,805 TONS	23.39	416,540	2,888,471	7.36
2	CRYSTAL RIVER 5	712	194,570	36.7	92.65	58.9	10,622	COAL	88,338 TONS	23.39	2,066,667	8,049,924	4.14
3	ANCLOTE 1	517	119,053	31.0	94.52	32.8	11,019	GAS	1,311,879 MCF	1.00	1,311,879	4,898,580	4.11
4	ANCLOTE 2	521	111,189	28.7	98.06	29.2	11,923	GAS	1,325,752 MCF	1.00	1,325,752	4,931,763	4.44
5	AVON PARK 1-2	69	0	0.0	94.16	0.0	0	GAS	0 MCF		0	0	0.00
6	BARTOW 1-4	228	27	0.0	81.69	11.8	14,185	GAS	383 MCF	1.00	383	1,843	6.83
7	BARTOW CC 1	1279	313,681	33.0	91.94	35.9	7,723	GAS	2,422,569 MCF	1.00	2,422,569	8,524,612	2.72
8	CITRUS CC 1-2	1640	1,134,920	93.0	95.81	97.6	6,529	GAS	7,410,220 MCF	1.00	7,410,220	27,494,587	2.42
9	DEBARY 1-10	785	9,885	1.7	91.57	10.2	12,806	GAS	126,596 MCF	1.00	126,596	462,510	4.68
10	HIGG NS 1-4	129	99	0.1	64.84	19.2	15,504	GAS	1,538 MCF	1.00	1,538	7,078	7.14
11	HINES CC 1-4	2,204	940,500	57.4	72.61	78.7	7,250	GAS	6,818,981 MCF	1.00	6,818,981	25,442,534	2.71
12	INT CITY 1-14	1,186	8,474	1.0	93.99	6.5	12,825	GAS	108,681 MCF	1.00	108,681	386,513	4.56
13	OSPREY CC 1	505	302,317	80.5	96.33	85.4	7,485	GAS	2,262,729 MCF	1.00	2,262,729	8,407,997	2.78
14	SUWANNEE CT 1-3	200	2,739	1.8	89.13	24.9	13,594	GAS	37,231 MCF	1.00	37,231	144,792	5.29
15	TIGER BAY CC 1	225	110,009	65.7	94.19	88.6	7,467	GAS	821,397 MCF	1.00	821,397	3,101,023	2.82
16	UNIV OF FLA. CC 1	47	17,107	48.9	95.44	93.6	9,387	GAS	160,578 MCF	1.00	160,578	613,269	3.58
17	AVON PARK 1-2	69	0	0.0	94.16	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
18	BARTOW 1-4	228	0	0.0	81.69	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
19	BAYBORO 1-4	231	0	0.0	91.85	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
20	DEBARY 1-10	785	0	0.0	91.57	0.0	0	LIGHT OIL	0 BBLS		0	2,082	0.00
21	HIGG NS 1-4	129	0	0.0	64.84	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
22	OTHER	0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
23	INT CITY 1-14	1,186	12	1.0	93.99	0.0	15,083	LIGHT OIL	31 BBLS	5.84	181	7,360	61.33
24	SUWANNEE 1-3	200	0	0.0	89.13	0.0	0	LIGHT OIL	0 BBLS		0	1,508	0.00
25	OTHER & START UP	-	0	-	72.61	0.0	0	LIGHT OIL	997 BBLS	5.83	5,810	157,125	0.00
26	SOLAR	92	18,693	27.3	93.99	59.2	0	SOLAR	0 N/A		0	0	0.00
27	TOTAL		3,322,506								25,297,732	95,523,571	2.88

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-19

(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	194,873	37.0	91.35	65.2	10,290	COAL	85,501 TONS	23.45	2,005,197	7,814,666	4.01
2 CRYSTAL RIVER	5	712	148,605	29.0	92.37	58.3	10,595	COAL	67,133 TONS	23.45	1,574,420	6,476,468	4.36
3 ANCLOTE	1	517	64,368	17.3	96.33	22.3	11,480	GAS	738,943 MCF	1 00	738,943	3,319,874	5.16
4 ANCLOTE	2	521	72,142	19.2	99.00	25.9	11,723	GAS	845,689 MCF	1 00	845,689	3,585,779	4.97
5 AVON PARK	1-2	69	0	0.0	93.92	0.0	0	GAS	0 MCF		0	0	0.00
6 BARTOW	1-4	228	0	0.0	83.99	0.0	0	GAS	0 MCF		0	0	0.00
7 BARTOW CC	1	1279	279,267	30.3	97.22	52.0	7,618	GAS	2,127,553 MCF	1 00	2,127,553	8,315,523	2.98
8 CITRUS CC	1-2	1640	587,958	49.8	50.38	48.8	6,502	GAS	3,823,048 MCF	1 00	3,823,048	15,861,855	2.70
9 DEBARY	1-10	785	1,049	0.2	92.23	8.9	13,041	GAS	13,680 MCF	1 00	13,680	84,066	8.01
10 HIGGINS	1-4	129	0	0.0	66.12	0.0	0	GAS	0 MCF		0	0	0.00
11 HINES CC	1-4	2,204	995,355	62.7	76.33	84.2	7,104	GAS	7,070,648 MCF	1 00	7,070,648	29,630,581	2.98
12 INT CITY	1-14	1,186	617	0.1	93.86	5.2	12,746	GAS	7,868 MCF	1 00	7,868	43,504	7.05
13 OSPREY CC	1	505	259,227	71.3	96.81	74.3	7,362	GAS	1,908,475 MCF	1 00	1,908,475	8,244,327	3.18
14 SUWANNEE CT	1-3	200	530	0.4	86.29	22.1	14,088	GAS	7,461 MCF	1 00	7,461	40,770	7.70
15 TIGER BAY CC	1	225	87,975	54.3	95.33	88.1	7,605	GAS	669,015 MCF	1 00	669,015	3,127,748	3.56
16 UNIV OF FLA. CC	1	47	30,624	90.5	96.64	93.6	9,369	GAS	286,906 MCF	1 00	286,906	1,219,934	3.98
17 AVON PARK	1-2	69	0	0.0	93.92	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
18 BARTOW	1-4	228	0	0.0	83.99	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
19 BAYBORO	1-4	231	0	0.0	91.77	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
20 DEBARY	1-10	785	0	0.0	92.23	0.0	0	LIGHT OIL	0 BBLS		0	2,082	0.00
21 HIGGINS	1-4	129	0	0.0	66.12	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
22 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
23 INT CITY	1-14	1,186	0	0.0	93.86	0.0	0	LIGHT OIL	0 BBLS		0	4,907	0.00
24 SUWANNEE	1-3	200	0	0.0	86.29	0.0	0	LIGHT OIL	0 BBLS		0	1,508	0.00
25 OTHER & START UP		-	0	-	76.33	0.0	0	LIGHT OIL	1,069 BBLS	5 82	6,225	162,277	0.00
26 SOLAR		92	15,320	23.1	93.86	52.5	0	SOLAR	0 N/A		0	0	0.00
27 TOTAL			2,737,910								21,085,128	87,935,869	3.21

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-19

(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	0	0.0	31.34	0.0	0	COAL	0	TONS		0	1,585,569	0.00
2 CRYSTAL RIVER	5	712	0	0.0	31.57	0.0	0	COAL	0	TONS		0	1,585,569	0.00
3 ANCLOTE	1	517	0	0.0	91.61	0.0	0	GAS	0	MCF		0	6,898	0.00
4 ANCLOTE	2	521	0	0.0	93.23	0.0	0	GAS	0	MCF		0	6,898	0.00
5 AVON PARK	1-2	69	0	0.0	92.99	0.0	0	GAS	0	MCF		0	0	0.00
6 BARTOW	1-4	228	0	0.0	84.67	0.0	0	GAS	0	MCF		0	0	0.00
7 BARTOW CC	1	1279	588,810	61.9	98.06	63.2	7,673	GAS	4,518,133	MCF	1 00	4,518,133	18,050,243	3.07
8 CITRUS CC	1-2	1640	1,213,700	99.5	98.07	51.1	6,499	GAS	7,888,344	MCF	1 00	7,888,344	32,502,851	2.68
9 DEBARY	1-10	785	1,921	0.3	92.96	9.1	13,213	GAS	25,375	MCF	1 00	25,375	107,559	5.60
10 HIGGINS	1-4	129	0	0.0	65.17	0.0	0	GAS	0	MCF		0	0	0.00
11 HINES CC	1-4	2,204	1,041,084	63.5	96.85	85.5	7,019	GAS	7,307,487	MCF	1 00	7,307,487	30,495,210	2.93
12 INT CITY	1-14	1,186	607	0.1	95.16	7.3	12,476	GAS	7,569	MCF	1 00	7,569	41,034	6.76
13 OSPREY CC	1	505	179,653	47.8	95.62	54.9	7,508	GAS	1,348,850	MCF	1 00	1,348,850	5,725,442	3.19
14 SUWANNEE CT	1-3	200	4,089	2.7	87.47	24.9	13,763	GAS	56,276	MCF	1 00	56,276	251,839	6.16
15 TIGER BAY CC	1	225	28,046	16.8	94.84	99.7	7,471	GAS	209,545	MCF	1 00	209,545	894,510	3.19
16 UNIV OF FLA. CC	1	47	33,230	95.0	97.13	97.9	9,359	GAS	311,007	MCF	1 00	311,007	1,314,287	3.96
17 AVON PARK	1-2	69	0	0.0	92.99	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
18 BARTOW	1-4	228	0	0.0	84.67	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
19 BAYBORO	1-4	231	0	0.0	91.46	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
20 DEBARY	1-10	785	0	0.0	92.96	0.0	0	LIGHT OIL	0	BBLS		0	2,082	0.00
21 HIGGINS	1-4	129	0	0.0	65.17	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
22 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
23 INT CITY	1-14	1,186	0	0.0	95.16	0.0	0	LIGHT OIL	0	BBLS		0	4,907	0.00
24 SUWANNEE	1-3	200	0	0.0	87.47	0.0	0	LIGHT OIL	0	BBLS		0	1,508	0.00
25 OTHER & START UP		-	0	-	96.85	0.0	0	LIGHT OIL	0	BBLS		0	77,504	0.00
26 SOLAR		92	24,589	35.9	95.16	80.3	0	SOLAR	0	N/A		0	0	0.00
27 TOTAL			3,115,729									21,672,586	92,653,910	2.97

Duke Energy Florida, LLC
Inventory Analysis
Estimated for the Period of : January 2019 through December 2019

			Act Jan-19	Act Feb-19	Act Mar-19	Act Apr-19	Act May-19	Act Jun-19	Subtotal
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	5,169	1,784	2,137	1,422	2,303	6,729	19,544
3	UNIT COST	$/BBL	128.58	131.28	132 63	132.37	135.35	135.57	132.75
4	AMOUNT	$	664,642	234,210	283,421	188,227	311,713	912,220	2,594,433
5	BURNED:								
6	UNITS	BBL	10,171	4,468	8,488	6,246	4,508	13,155	47,036
7	UNIT COST	$/BBL	125.87	111.91	108.76	110.81	123.83	118.91	117.31
8	AMOUNT	$	1,280,215	500,019	923,169	692,111	558,241	1,564,207	5,517,961
9	ENDING INVENTORY:								
10	UNITS	BBL	681,908	679,223	672,872	668,058	665,853	659,427	
11	UNIT COST	$/BBL	108.78	108.82	108.89	108 92	108.91	108.99	
12	AMOUNT	$	74,175,916	73,910,108	73,270,360	72,766,475	72,519,947	71,867,960	
	COAL								
13	PURCHASES:								
14	UNITS	TON	157,321	73,525	18,742	73,116	111,305	172,983	606,992
15	UNIT COST	$/TON	93.15	66.06	193.13	127.71	86.89	85.78	93.87
16	AMOUNT	$	14,654,389	4,857,279	3,619,657	9,337,460	9,671,125	14,837,992	56,977,901
17	BURNED:								
18	UNITS	TON	129,315	17,108	143,944	145,073	156,909	223,183	815,532
19	UNIT COST	$/TON	75.14	74.14	77.47	83.82	84.46	85.36	81.67
20	AMOUNT	$	9,717,146	1,268,395	11,151,969	12,160,194	13,253,021	19,050,460	66,601,186
21	ENDING INVENTORY:								
22	UNITS	TON	653,940	710,357	585,155	513,198	467,594	417,395	
23	UNIT COST	$/TON	77.37	76.28	79.73	85.41	86.08	86.34	
24	AMOUNT	$	50,598,408	54,187,292	46,654,979	43,832,245	40,250,349	36,037,880	
	GAS								
25	BURNED:								
26	UNITS	MCF	19,200,944	17,922,366	17,286,942	19,557,528	24,285,821	26,151,841	124,405,442
27	UNIT COST	$/MCF	5.15	4.49	4 62	4.27	3.96	3.76	4.32
28	AMOUNT	$	98,979,603	80,559,232	79,842,503	83,424,699	96,106,429	98,362,310	537,274,776

Duke Energy Florida, LLC
Inventory Analysis
Estimated for the Period of : January 2019 through December 2019

			Est Jul-19	Est Aug-19	Est Sep-19	Est Oct-19	Est Nov-19	Est Dec-19	Total
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	1,170	915	498	1,028	1,069	0	24,224
3	UNIT COST	$/BBL	152.75	173.48	252.66	163.50	159.75	0 00	143.76
4	AMOUNT	$	178,715	158,732	125,827	168,075	170,774	86,001	3,482,557
5	BURNED:								
6	UNITS	BBL	1,170	915	498	1,028	1,069	0	51,716
7	UNIT COST	$/BBL	152.75	173.48	252.66	163.50	159.75	0 00	123.87
8	AMOUNT	$	178,715	158,732	125,827	168,075	170,774	86,001	6,406,085
9	ENDING INVENTORY:								
10	UNITS	BBL	659,427	659,427	659,427	659,427	659,427	659,427	
11	UNIT COST	$/BBL	108 99	108.99	108.99	108.99	108.99	108 99	
12	AMOUNT	$	71,867,960	71,867,960	71,867,960	71,867,960	71,867,960	71,867,960	
	COAL								
13	PURCHASES:								
14	UNITS	TON	223,375	201,849	167,037	106,143	152,634	0	1,540,222
15	UNIT COST	$/TON	88 60	89.45	92.53	103.05	93.63	0.00	94.84
16	AMOUNT	$	19,789,982	18,055,094	15,456,479	10,938,395	14,291,134	3,171,138	146,076,283
17	BURNED:								
18	UNITS	TON	223,375	201,849	167,037	106,143	152,634	0	1,666,570
19	UNIT COST	$/TON	88 60	89.45	92.53	103.05	93.63	0 00	88.99
20	AMOUNT	$	19,789,982	18,055,094	15,456,479	10,938,395	14,291,134	3,171,138	148,303,408
21	ENDING INVENTORY:								
22	UNITS	TON	417,395	417,395	417,395	417,395	417,395	417,395	
23	UNIT COST	$/TON	86 34	86.34	86.34	86.34	86.34	86.34	
24	AMOUNT	$	36,037,880	36,037,880	36,037,880	36,037,880	36,037,880	36,037,880	
	GAS								
25	BURNED:								
26	UNITS	MCF	26,867,149	27,179,166	25,656,038	22,808,534	17,499,286	21,672,586	266,088,201
27	UNIT COST	$/MCF	3.63	3.62	3.62	3.70	4.20	4.12	4.03
28	AMOUNT	$	97,461,751	98,376,699	92,924,911	84,417,101	73,473,961	89,396,771	1,073,325,970

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2019 through December 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	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)	GAIN ON POWER SALES $
Jan-19	ECONSALE	--	23,735		23,735	2.893	4.127	686,538	979,519	292,981
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	--	94,267		94,267	2.249	2.249	2,120,491	2,120,491	0
	TOTAL		118,002		118,002	2.379	2.627	2,807,029	3,100,010	292,981
Feb-19	ECONSALE	--	1,758		1,758	2.110	-1.211	37,098	(21,292)	(58,390)
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	--	90,455		90,455	1.658	1.658	1,499,837	1,499,837	0
	TOTAL		92,213		92,213	1.667	1.603	1,536,936	1,478,546	(58,390)
Mar-19	ECONSALE	--	7,628		7,628	3.464	5.109	264,257	389,677	125,420
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	--	114,578		114,578	1.630	1.630	1,867,338	1,867,338	0
	TOTAL		122,206		122,206	1.744	1.847	2,131,595	2,257,015	125,420
Apr-19	ECONSALE	--	13,165		13,165	3.793	5.004	499,381	658,840	159,460
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	--	121,884		121,884	1.825	1.825	2,224,625	2,224,625	0
	TOTAL		135,049		135,049	2.017	2.135	2,724,006	2,883,465	159,460
May-19	ECONSALE	--	16,019		16,019	3.710	5.857	594,272	938,177	343,905
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	--	188,198		188,198	1.761	1.761	3,314,209	3,314,209	0
	TOTAL		204,217		204,217	1.914	2.082	3,908,481	4,252,385	343,905
Jun-19	ECONSALE	--	13,705		13,705	3.437	4.817	471,077	660,154	189,077
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	--	424,304		424,304	2.113	2.113	8,963,528	8,963,528	0
	TOTAL		438,009		438,009	2.154	2.197	9,434,605	9,623,682	189,077
Jan-19	ECONSALE	--	76,010		76,010	3.358	4.743	2,552,624	3,605,075	1,052,451
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Jun-19	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,033,686		1,033,686	1.934	1.934	19,990,028	19,990,028	0
	TOTAL		1,109,696		1,109,696	2.031	2.126	22,542,652	23,595,103	1,052,451

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2019 through December 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	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)	GAIN ON POWER SALES $
Jul-19	ECONSALE	--	16,372		16,372	3.362	4.251	550,381	696,046	145,665
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	--	311,259		311,259	2.381	2.381	7,410,962	7,410,962	0
	TOTAL		327,631		327,631	2.430	2.474	7,961,343	8,107,008	145,665
Aug-19	ECONSALE	--	20,354		20,354	3.963	5.012	806,661	1,020,154	213,493
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(15,580)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	296,076		296,076	2.379	2.379	7,042,783	7,042,783	0
	TOTAL		316,429		316,429	2.481	2.548	7,849,444	8,062,937	197,913
Sep-19	ECONSALE	--	11,770		11,770	3.522	4.455	414,607	524,337	109,730
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(21,946)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	270,424		270,424	2.366	2.366	6,398,362	6,398,362	0
	TOTAL		282,195		282,195	2.414	2.453	6,812,969	6,922,699	87,784
Oct-19	ECONSALE	--	5,065		5,065	3.117	3.942	157,883	199,669	41,786
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(8,357)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	254,852		254,852	2.473	2.473	6,302,711	6,302,711	0
	TOTAL		259,916		259,916	2.486	2.502	6,460,594	6,502,380	33,429
Nov-19	ECONSALE	--	3,544		3,544	3.896	4.927	138,100	174,650	36,550
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(7,310)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	131,376		131,376	2.664	2.664	3,500,346	3,500,346	0
	TOTAL		134,920		134,920	2.697	2.724	3,638,446	3,674,996	29,240
Dec-19	ECONSALE	--	8,274		8,274	2.592	3.278	214,445	271,201	56,756
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(11,351)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	156,130		156,130	2.567	2.567	4,008,072	4,008,072	0
	TOTAL		164,404		164,404	2.568	2.603	4,222,517	4,279,273	45,405
Jan-19	ECONSALE	--	141,389		141,389	3.419	4.591	4,834,701	6,491,132	1,656,431
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-19	EXCESS GAIN	--	0		0	0.000	0.000	0	(64,544)	(64,544)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	2,453,803		2,453,803	2.227	2.227	54,653,263	54,653,263	0
	TOTAL		2,595,192		2,595,192	2.292	2.354	59,487,964	61,079,851	1,591,887

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2019 through December 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jan-19	OTHER	--	0			0	0 000	0 000	0
Act	SHADY H LLS	--	6,704			6,704	6 057	6 057	406,053
	SOCO Franklin	--	58,300			58,300	4 245	4 245	2,474,968
	Vandolah (NSG)	--	18,094			18,094	4 581	4 581	828,938
	TOTAL		83,098	0	0	83,098	4.465	4.465	3,709,959
Feb-19	OTHER	--	0			0	0 000	0 000	0
Act	SHADY H LLS	--	(979)			(979)	-6.192	-6.192	60,615
	SOCO Franklin	--	36,903			36,903	4 387	4 387	1,619,081
	Vandolah (NSG)	--	14,493			14,493	6 688	6 688	969,259
	TOTAL		50,417	0	0	50,417	5 254	5 254	2,648,955
Mar-19	OTHER	--	0			0	0 000	0 000	0
Act	SHADY H LLS	--	8,349			8,349	7.447	7.447	621,758
	SOCO Franklin	--	66,296			66,296	3 877	3 877	2,570,318
	Vandolah (NSG)	--	27,417			27,417	7 076	7 076	1,940,112
	TOTAL		102,062	0	0	102,062	5 029	5 029	5,132,188
Apr-19	OTHER	--	0			0	0 000	0 000	0
Act	SHADY H LLS	--	14,823			14,823	6 264	6 264	928,485
	SOCO Franklin	--	49,185			49,185	4.111	4.111	2,021,943
	Vandolah (NSG)	--	58,618			58,618	5 624	5 624	3,296,912
	TOTAL		122,626	0	0	122,626	5 095	5 095	6,247,340
May-19	OTHER	--	0			0	0 000	0 000	0
Act	SHADY H LLS	--	33,784			33,784	6 043	6 043	2,041,548
	SOCO Franklin	--	153,912			153,912	3 256	3 256	5,011,770
	Vandolah (NSG)	--	121,366			121,366	5.179	5.179	6,286,045
	TOTAL		309,062	0	0	309,062	4 316	4 316	13,339,364
Jun-19	OTHER	--	0			0	0 000	0 000	0
Act	SHADY H LLS	--	31,170			31,170	5 983	5 983	1,864,864
	SOCO Franklin	--	164,228			164,228	2 978	2 978	4,891,270
	Vandolah (NSG)	--	115,665			115,665	5 251	5 251	6,073,759
	TOTAL		311,063	0	0	311,063	4.125	4.125	12,829,894
Jan-19	OTHER	--	0			0	0 000	0 000	0
THRU	SHADY H LLS	--	93,851			93,851	6 311	6 311	5,923,324
Jun-19	SOCO Franklin	--	528,824			528,824	3 515	3 515	18,589,352
	Vandolah (NSG)	--	355,653			355,653	5.453	5.453	19,395,023
	TOTAL		978,328	0	0	978,328	4.488	4.488	43,907,699

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2019 through December 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR NTERRUPTIBLE	MWH FOR F RM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-19	OTHER	--	0			0	0.000	0 000	0
Est	SHADY HILLS	--	109,365			109,365	3.950	3 950	4,320,248
	SOCO Franklin	--	116,497			116,497	2.548	2 548	2,968,528
	Vandolah (NSG)	--	17,983			17,983	4.983	4 983	896,062
	TOTAL		243,846	0	0	243,846	3.357	3 357	8,184,838
Aug-19	OTHER	--	0			0	0.000	0 000	0
Est	SHADY HILLS	--	75,568			75,568	3.984	3 984	3,010,454
	SOCO Franklin	--	113,374			113,374	2.564	2 564	2,906,702
	Vandolah (NSG)	--	19,433			19,433	4.937	4 937	959,426
	TOTAL		208,376	0	0	208,376	3.300	3 300	6,876,582
Sep-19	OTHER	--	0			0	0.000	0 000	0
Est	SHADY HILLS	--	82,843			82,843	3.917	3 917	3,245,019
	SOCO Franklin	--	105,793			105,793	2.545	2 545	2,692,710
	Vandolah (NSG)	--	18,295			18,295	4.602	4 602	841,852
	TOTAL		206,931	0	0	206,931	3.276	3 276	6,779,581
Oct-19	OTHER	--	0			0	0.000	0 000	0
Est	SHADY HILLS	--	92,865			92,865	4.241	4 241	3,938,107
	SOCO Franklin	--	98,831			98,831	2.571	2 571	2,541,298
	Vandolah (NSG)	--	13,514			13,514	4.860	4 860	656,755
	TOTAL		205,209	0	0	205,209	3.478	3.478	7,136,160
Nov-19	OTHER	--	0			0	0.000	0 000	0
Est	SHADY HILLS	--	5,779			5,779	7.861	7 861	454,290
	SOCO Franklin	--	90,104			90,104	2.568	2 568	2,314,181
	Vandolah (NSG)	--	384			384	19.841	19.841	76,191
	TOTAL		96,267	0	0	96,267	2.955	2 955	2,844,662
Dec-19	OTHER	--	0			0	0.000	0 000	0
Est	SHADY HILLS	--	9,396			9,396	4.850	4 850	455,700
	SOCO Franklin	--	14,321			14,321	2.761	2.761	395,354
	Vandolah (NSG)	--	4,457			4,457	5.737	5.737	255,716
	TOTAL		28,174	0	0	28,174	3.928	3 928	1,106,770
Jan-19	OTHER	--	0			0	0.000	0 000	-
THRU	SHADY HILLS	--	469,668			469,668	4.545	4 545	21,347,142
Dec-19	SOCO Franklin	--	1,067,744			1,067,744	3.035	3 035	32,408,125
	Vandolah (NSG)	--	429,719			429,719	5.371	5 371	23,081,025
TOTAL			1,967,131	0	0	1,967,131	3.906	3 906	76,836,292

Duke Energy Florida, LLC
Energy Payments to Qualifying Facilities
Estimated for the Period of : January 2019 through December 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILIT ES	MWH FOR INTERRUPTIBLE	MWH FOR F RM	(A) ENERGY COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(A)
Jan-19 Act	QUAL. FAC LITIES	COGEN	249,229			249,229	4.377	15.033	10,908,157
Feb-19 Act	QUAL. FAC LITIES	COGEN	195,731			195,731	3.884	17.043	7,601,725
Mar-19 Act	QUAL. FAC LITIES	COGEN	193,577			193,577	3.786	17.092	7,328,667
Apr-19 Act	QUAL. FAC LITIES	COGEN	165,023			165,023	4.281	19.889	7,064,641
May-19 Act	QUAL. FAC LITIES	COGEN	215,766			215,766	4.117	16.054	8,882,702
Jun-19 Act	QUAL. FAC LITIES	COGEN	222,053			222,053	4.157	15.757	9,231,306
Jul-19 Est	QUAL. FAC LITIES	COGEN	257,982			257,982	4.005	13.989	10,332,497
Aug-19 Est	QUAL. FAC LITIES	COGEN	257,982			257,982	3.988	13.972	10,289,444
Sep-19 Est	QUAL. FAC LITIES	COGEN	231,096			231,096	3.962	15.107	9,155,724
Oct-19 Est	QUAL. FAC LITIES	COGEN	234,003			234,003	4.163	15.170	9,742,112
Nov-19 Est	QUAL. FAC LITIES	COGEN	247,526			247,526	3.984	14.389	9,860,682
Dec-19 Est	QUAL. FAC LITIES	COGEN	254,820			254,820	3.935	14.042	10,026,097
TOTAL	QUAL. FAC LITIES	COGEN	2,724,789			2,724,789	4.053	15.425	110,423,752

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2019 through December 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-19	ECONPURCH	--	4,572	4.031	4.031	184,282	4.100	187,433	3,151
Act	SEPA	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		4,572	4.031	4.031	184,282	4.100	187,433	3,151
Feb-19	ECONPURCH	--	7,957	3.018	3.018	240,158	3.370	268,112	27,955
Act	SEPA	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		7,957	3.018	3.018	240,158	3.370	268,112	27,955
Mar-19	ECONPURCH	--	4,566	3.982	3.982	181,800	4.218	192,616	10,816
Act	SEPA	--	1,476	4.634	4.634	68,403	4.634	68,403	0
	TOTAL		6,042	4.141	4.141	250,203	4.320	261,018	10,816
Apr-19	ECONPURCH	--	7,605	3.423	3.423	260,334	3.943	299,830	39,496
Act	SEPA	--	2,957	3.993	3.993	118,063	3.993	118,063	0
	TOTAL		10,562	3.583	3.583	378,398	3.957	417,893	39,496
May-19	ECONPURCH	--	7,825	4.060	4.060	317,734	4.034	315,641	(2,093)
Act	SEPA	--	4,132	3.494	3.494	144,379	3.494	144,379	0
	TOTAL		11,957	3.865	3.865	462,113	3.847	460,020	(2,093)
Jun-19	ECONPURCH	--	5,014	5.617	5.617	281,636	3.613	181,156	(100,480)
Act	SEPA	--	6,571	3.588	3.588	235,768	3.588	235,768	0
	TOTAL		11,585	4.466	4.466	517,405	3.599	416,925	(100,480)
Jan-19	ECONPURCH	--	37,539	3.905	3.905	1,465,944	3.849	1,444,787	(21,156)
THRU	SEPA	--	15,136	3.743	3.743	566,614	3.743	566,614	0
Jun-19									
	TOTAL		52,675	3.859	3.859	2,032,557	3.819	2,011,401	(21,156)

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2019 through December 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-19	ECONPURCH	--	4,267	4.411	4.411	188,238	5.096	217,445	29,207
Est	SEPA	--	0	0.000	0.000	0	0 000	0	-
	TOTAL		4,267	4.411	4.411	188,238	5 096	217,445	29,207
Aug-19	ECONPURCH	--	2,746	4.511	4.511	123,884	5.211	143,106	19,222
Est	SEPA	--	0	0.000	0.000	0	0 000	0	-
	TOTAL		2,746	4.511	4 511	123,884	5 211	143,106	19,222
Sep-19	ECONPURCH	--	2,825	4.540	4.540	128,246	5.244	148,144	19,898
Est	SEPA	--	0	0.000	0.000	0	0 000	0	-
	TOTAL		2,825	4.540	4 540	128,246	5 244	148,144	19,898
Oct-19	ECONPURCH	--	3,292	4.181	4.181	137,662	4.830	159,022	21,360
Est	SEPA	--	0	0.000	0.000	0	0 000	0	-
	TOTAL		3,292	4.181	4.181	137,662	4 830	159,022	21,360
Nov-19	ECONPURCH	--	2,540	3.519	3.519	89,384	4.065	103,253	13,869
Est	SEPA	--	0	0.000	0.000	0	0 000	0	-
	TOTAL		2,540	3.519	3 519	89,384	4 065	103,253	13,869
Dec-19	ECONPURCH	--	6,202	3.598	3.598	223,111	4.156	257,734	34,623
Est	SEPA	--	0	0.000	0.000	0	0 000	0	-
	TOTAL		6,202	3.598	3 598	223,111	4.156	257,734	34,623
Jan-19	ECONPURCH	--	59,412	3.966	3.966	2,356,469	4.163	2,473,491	117,023
THRU	SEPA	--	15,136	3.743	3.743	566,614	3.743	566,614	0
Dec-19									
	TOTAL		74,548	3.921	3 921	2,923,082	4 078	3,040,105	117,023

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : January 2019 through June 2019

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	PreTax Weighted Cost Rate
Common Equity	$ 4,374,787	40.92%	10.50%	4.30%	5.75%
Long Term Debt	4,497,052	42.06%	4.90%	2.06%	2.06%
Short Term Debt	(193,058)	-1.81%	0.88%	-0.02%	-0.02%
Customer Deposits - Active	179,649	1.68%	2.35%	0.04%	0.04%
Customer Deposits - Inactive	1,597	0.01%	0.00%	0.00%	0.00%
Deferred Tax	1,826,909	17.09%	0.00%	0.00%	0.00%
Deferred Tax (FAS 109)	-	0.00%	0.00%	0.00%	0.00%
ITC	5,239	0.05%	7.85%	0.00%	0.00%
	10,692,175	89.96%		6.38%	7.84%
			Total Debt	2.09%	2.09%
			Total Equity	4.30%	5.75%

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

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : July 2019 through December 2019

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	PreTax Weighted Cost Rate
Common Equity	$ 4,874,577	41.01%	10.50%	4.31%	5.77%
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%
Deferred Tax (FAS 109)	-	0.00%	0.00%	0.00%	0.00%
ITC	19,806	0.17%	7.71%	0.01%	0.01%
	$ 11,884,905	100.00%		6.27%	7.74%
			Total Debt	1.97%	1.97%
			Total Equity	4.31%	5.77%

Above is the May 2019 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

Docket No. 20190001-EI
Exhibit No. ____(CAM-2)
Part 2

DUKE ENERGY FLORIDA, LLC

Capacity Cost Recovery

Actual / Estimated True-Up

January through December 2019

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

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

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

Duke Energy Florida, LLC
Calculation of Projected Capacity Costs
For the Year 2019

Docket No. 20190001-EI
Exhibit__CAM-2, Part 2
Schedule E12-A
Page 1 of 1

		EST Jan-19	EST Feb-19	EST Mar-19	EST Apr-19	EST May-19	EST Jun-19	EST Jul-19	EST Aug-19	EST Sep-19	EST Oct-19	EST Nov-19	EST Dec-19	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	67,211,202
3	Orlando Cogen Limited (ORLACOGL)	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	67,633,941
4	Pasco County Resource Recovery (PASCOUNT)	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	24,230,040
5	Pinellas County Resource Recovery (PINCOUNT)	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	57,678,030
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	92,326,984
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,611,349
8	US EcoGen	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Subtotal - Base Level Capacity Costs	26,557,629	26,557,629	26,557,629	26,557,629	26,557,629	26,557,629	26,557,629	26,557,629	26,557,629	26,557,629	26,557,629	26,557,629	318,691,546
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	24,668,054	24,668,053	24,668,053	24,668,053	24,668,053	24,668,054	24,668,054	24,668,054	24,668,054	24,668,054	24,668,054	24,668,054	296,016,640
12	**Intermediate Production Level Capacity Costs**													
13	Southern Franklin	4,827,230	4,827,230	2,888,986	2,888,986	3,165,878	5,441,774	6,566,702	6,566,702	4,879,310	2,910,686	2,910,686	3,754,382	51,628,548
14	Schedule H Capacity Sales - NSB	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Subtotal - Intermediate Level Capacity Costs	4,827,230	4,827,230	2,888,986	2,888,986	3,165,878	5,441,774	6,566,702	6,566,702	4,879,310	2,910,686	2,910,686	3,754,382	51,628,548
16	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%	
17	Intermediate Level Jurisdict. Capacity Costs	3,509,541	3,509,541	2,100,379	2,100,379	2,301,689	3,956,333	4,774,189	4,774,189	3,547,405	2,116,156	2,116,156	2,729,548	37,535,504
18	**Peaking Production Level Capacity Costs**													
19	Shady Hills	1,983,330	1,983,330	1,416,664	1,374,376	1,924,126	3,911,684	3,911,684	3,911,684	1,825,453	1,374,376	1,374,376	1,983,330	26,974,412
20	Vandolah (NSG)	2,772,661	2,788,227	1,998,461	1,976,224	2,694,834	5,556,300	5,539,623	5,495,150	2,629,977	1,937,310	1,981,783	2,788,227	38,158,778
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal - Peaking Level Capacity Costs	4,755,991	4,771,557	3,415,125	3,350,600	4,618,959	9,467,985	9,451,307	9,406,834	4,455,430	3,311,686	3,356,159	4,771,557	65,133,189
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	4,562,137	4,577,068	3,275,924	3,214,029	4,430,691	9,082,070	9,066,072	9,023,412	4,273,827	3,176,702	3,219,362	4,577,068	62,478,361
25	**Other Capacity Costs**													
26	Retail Wheeling	(73,776)	(27,192)	(3,832)	(2,388)	(16,640)	(28,097)	(40,215)	(43,409)	(23,956)	(15,958)	(13,467)	(16,708)	(305,637)
27	Total Other Capacity Costs	(73,776)	(27,192)	(3,832)	(2,388)	(16,640)	(28,097)	(40,215)	(43,409)	(23,956)	(15,958)	(13,467)	(16,708)	(305,637)
28	**Total Capacity Costs (line 11+17+24+27)**	32,665,956	32,727,470	30,040,525	29,980,074	31,383,793	37,678,359	38,468,100	38,422,245	32,465,329	29,944,953	29,990,104	31,957,962	395,724,869
29	Actual/Estimated True-Up Provision - Jan - Dec 2018													(16 610 473)
30	**Total Capacity Costs w/ True-Up**													379,114,396
31	Revenue Tax Multiplier													1.00072
32	**Total Recoverable Capacity Costs**													379,387,358
33	**Nuclear Cost Recovery Clause**													43,827,298
34	Revenue Tax Multiplier													1.00072
35	**Total Recoverable Nuclear Costs**													43,858,854
36	**ISFSI Revenue Requirement**[1]													6,885,178
37	Revenue Tax Multiplier													1.00072
38	**Total Recoverable ISFSI Costs**													6,890,135
39	**Total Recov Capacity & Nuclear Costs (line 32+35+38)**													430,136,347

[1] Approved in Commission Order No. PSC-2016-0425-PAA-EI.

Duke Energy Florida, LLC
Calculation of Actual/Estimated Capacity True-up
For the Year 2019

Docket No. 20190001-EI
Exhibit__CAM-2, Part 2
Schedule E12-B
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		ACT Jan-19	ACT Feb-19	ACT Mar-19	ACT Apr-19	ACT May-19	ACT Jun-19	EST Jul-19	EST Aug-19	EST Sep-19	EST Oct-19	EST Nov-19	EST Dec-19	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	67,211,204
3	Orlando Cogen Limited (ORLACOGL)	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	67,633,942
4	Pasco County Resource Recovery (PASCOUNT)	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	24,230,040
5	Pinellas County Resource Recovery (PINCOUNT)	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	57,678,030
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	92,326,986
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	0	-	-	-	-	-	-	-	-	-	-	800,946
8	Subtotal - Base Level Capacity Costs	26,557,630	25,756,684	25,756,684	25,756,684	25,756,684	25,756,684	25,756,683	25,756,683	25,756,683	25,756,683	25,756,683	25,756,683	309,881,148
9	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%	
10	Base Level Jurisdictional Capacity Costs	24,668,054	23,924,096	23,924,096	23,924,096	23,924,096	23,924,096	23,924,095	23,924,095	23,924,095	23,924,095	23,924,095	23,924,095	287,833,104
11	**Intermediate Production Level Capacity Costs**													
12	Southern Franklin	4,611,942	4,802,362	2,752,978	2,755,639	2,814,130	5,254,911	6,374,293	6,374,293	4,712,941	2,774,697	2,774,697	3,605,373	49,608,256
13	Schedule H Capacity Sales	(48,411)	-	(64,548)	-	-	(114,031)	-	-	-	-	-	-	(226,990)
14	Subtotal - Intermediate Level Capacity Costs	4,563,531	4,802,362	2,688,430	2,755,639	2,814,130	5,140,880	6,374,293	6,374,293	4,712,941	2,774,697	2,774,697	3,605,373	49,381,266
15	Intermediate Production Jurisdictioinal 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%	
16	Intermediate Level Jurisdictional Capacity Costs	3,317,824	3,491,461	1,954,569	2,003,433	2,045,957	3,737,574	4,634,302	4,634,302	3,426,450	2,017,288	2,017,288	2,621,214	35,901,661
17	**Peaking Production Level Capacity Costs**													
18	Shady Hills	1,976,940	1,976,940	1,412,100	1,366,200	1,912,680	3,888,000	3,901,517	3,901,517	1,820,708	1,370,803	1,370,803	1,978,175	26,876,383
19	Vandolah	2,919,279	2,891,051	1,947,614	1,942,582	2,793,653	5,773,604	5,536,005	5,491,562	2,628,284	1,936,075	1,980,519	2,786,429	38,626,658
20	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Subtotal - Peaking Level Capacity Costs	4,896,219	4,867,991	3,359,714	3,308,782	4,706,333	9,661,604	9,437,522	9,393,079	4,448,992	3,306,878	3,351,322	4,764,603	65,503,041
22	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%	
23	Peaking Level Jurisdictional Capacity Costs	4,696,650	4,669,572	3,222,772	3,173,916	4,514,503	9,267,797	9,052,849	9,010,217	4,267,651	3,172,090	3,214,722	4,570,398	62,833,137
24	**Other Capacity Costs**													
25	Retail Wheeling	(45,534)	(8,443)	(35,373)	(39,200)	(57,327)	(29,146)	(27,612)	(34,680)	(22,418)	(10,341)	(6,562)	(15,612)	(332,248)
26	Ridge Generating Station L P. Termination [1]	-	750,770	747,221	743,672	740,123	736,573	730,453	726,952	723,451	719,950	716,449	712,948	8,048,562
27	Total Other Capacity Costs	(45,534)	742,327	711,848	704,472	682,796	707,428	702,842	692,272	701,033	709,609	709,887	697,335	7,716,315
28	**Total Capacity Costs (Line 10+16+23+27)**	32,636,994	32,827,456	29,813,285	29,805,916	31,167,352	37,636,894	38,314,088	38,260,887	32,319,229	29,823,082	29,865,992	31,813,043	394,284,217
29	**Nuclear Cost Recovery Clause**													
30	CR3 Uprate Costs [2]	3 775 626	3 753 198	3 730 770	3 708 343	3 685 916	3 663 488	3 641 061	3 618 633	3 596 207	3 573 779	3 551 352	3 528 924	43 827 298
31	**Total Nuclear Cost Recovery Clause Costs**	3,775,626	3,753,198	3,730,770	3,708,343	3,685,916	3,663,488	3,641,061	3,618,633	3,596,207	3,573,779	3,551,352	3,528,924	43,827,298
32	**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
33	**Total Recov Capacity & Nuclear Costs (Line 28+31+32)**	36,985,939	37,153,974	34,117,375	34,087,579	35,426,587	41,873,703	42,528,468	42,452,840	36,488,756	33,970,181	33,990,663	35,915,287	444,991,352
34	**Capacity Revenues**													
35	Capacity Cost Recovery Revenues (net of tax)	29,661,483	30,804,405	30,389,686	31,169,336	34,653,964	41,304,162	42,125,264	42,483,642	43,580,645	39,787,264	33,521,424	31,582,385	431,063,659
36	Prior Period True-Up Provision Over/(Under) Recovery	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	16,610,473
37	**Current Period Revenues (net of tax)**	31,045,689	32,188,611	31,773,892	32,553,542	36,038,171	42,688,368	43,509,470	43,867,848	44,964,851	41,171,470	34,905,630	32,966,591	447,674,132
38	**True-Up Provision**													
39	True-Up Provision - Over/(Under) Recov (Line 37-33)	(5,940,250)	(4,965,363)	(2,343,483)	(1,534,037)	611,583	814,665	981,002	1,415,008	8,476,095	7,201,289	914,967	(2,948,696)	2,682,780
40	Interest Provision for the Month	24,206	10,633	535	(6,274)	(9,873)	(10,962)	(6,166)	(6,142)	802	6,504	6,050	1,810	11,121
41	Current Cycle Balance - Over/(Under)	(5,916,044)	(10,870,774)	(13,213,723)	(14,754,034)	(14,152,324)	(13,348,621)	(12,373,785)	(10,964,919)	(2,488,022)	4,719,770	5,640,787	2,693,901	2,693,901
42	Prior Period Balance - Over/(Under) Recovered	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080
43	Prior Period Cumulative True-Up Collected/(Refunded)	(1,384,206)	(2,768,412)	(4,152,618)	(5,536,824)	(6,921,030)	(8,305,235)	(9,689,442)	(11,073,648)	(12,457,854)	(13,842,060)	(15,226,266)	(16,610,472)	(16,610,472)
44	Prior Period True-up Balance - Over/(Under)	14,380,874	12,996,668	11,612,462	10,228,256	8,844,049	7,459,844	6,075,638	4,691,432	3,307,226	1,923,020	538,814	(845,392)	(845,392)
45	**Net Capacity True-up Over/(Under) (Line 41+44)**	$8,464,830	$2,125,894	($1,601,260)	($4,525,777)	($5,308,274)	($5,888,777)	($6,298,147)	($6,273,487)	$819,204	$6,642,790	$6,179,601	$1,848,509	$1,848,509

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] Approved in Commission Order No. PSC-2018-0490-FOF-EI.
[3] Approved in Commission Order No. PSC-2016-0425-PAA-EI.

Contract Data:

	Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
1	Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	115.00
2	Orange Cogen (ORANGECO)	Jul-95	Dec-25	QF	Purch	104.00
3	Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
4	Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
5	Polk Power Partners, L. P. (MULBERY/ROYSTER)	Aug-94	Aug-24	QF	Purch	115.00
6	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	Aug-94	Jan-19	QF	Purch	39.60
7	Southern - Franklin	Jun-16	May-21	Other	Purch	424.00
8	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	1.00
9	Vandolah (NSG)	Jun-12	May-27	Other	Purch	655.00
10	Shady Hills Tolling Agreement	Apr-07	Apr-24	Other	Purch	515.00

(1) The New Smyrna Beach (NSB) Schedule H contract is in effect until cancelled by either Duke Energy Florida or NSB upon 1 year's written notice.

		Re-Projection Total	Original Projection Total	Variance Total
1	**Capacity Revenues**			
2	Capacity Cost Recovery Revenues (net of tax)	$431,063,659	$429,826,872	$1,236,788
3	Prior Period True-Up Provision Over/(Under) Recovery	16,610,473	16,610,473	0
4	**Current Period Revenues (net of tax)**	447,674,132	446,437,345	1,236,788
5				
6	**Capacity Costs**			
7	**Base Production Level Capacity Costs**			
8	Orange Cogen (ORANGECO)	67,211,204	67,211,202	2
9	Orlando Cogen Limited (ORLACOGL)	67,633,942	67,633,941	1
10	Pasco County Resource Recovery (PASCOUNT)	24,230,040	24,230,040	0
11	Pinellas County Resource Recovery (PINCOUNT)	57,678,030	57,678,030	0
12	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	92,326,986	92,326,984	2
13	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	9,611,349	(8,810,403)
14	Subtotal - Base Level Capacity Costs	309,881,148	318,691,546	(8,810,398)
15	Base Production Jurisdictional Responsibility	92.885%	92.885%	0.000%
16	Base Level Jurisdictional Capacity Costs	287,833,104	296,016,640	(8,183,536)
17				
18	**Intermediate Production Level Capacity Costs**			
19	Southern - Franklin	49,608,256	51,628,548	(2,020,292)
20	Schedule H Capacity Sales	(226,990)	0	(226,990)
21	Subtotal - Intermediate Level Capacity Costs	49,381,266	51,628,548	(2,247,282)
22	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	0.000%
23	Intermediate Level Jurisdictional Capacity Costs	35,901,661	37,535,504	(1,633,843)
24				
25	**Peaking Production Level Capacity Costs**			
26	Shady Hills	26,876,383	26,974,412	(98,028)
27	Vandolah (NSG)	38,626,658	38,158,778	467,880
28	Subtotal - Peaking Level Capacity Costs	65,503,041	65,133,189	369,851
29	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	0.000%
30	Peaking Level Jurisdictional Capacity Costs	62,833,137	62,478,361	354,776
31				
32	**Other Capacity Costs**			
33	Retail Wheeling	(332,248)	(305,637)	(26,611)
34	Ridge Generating Station L.P. Termination [1]	8,048,562	0	8,048,562
35	Other Jurisdictional Capacity Costs	7,716,315	(305,637)	8,021,952
36				
37	**Subtotal Jurisdictional Capacity Costs (Line 16+23+30+35)**	394,284,217	395,724,869	(1,440,651)
38				
39	**Nuclear Cost Recovery Clause**			
40	CR3 Uprate Costs [2]	43,827,298	43,827,298	0
41	**Total Nuclear Cost Recovery Clause Costs**	43,827,298	43,827,298	0
42				
43	**ISFSI Revenue Requirement** [3]	6,879,837	6,885,178	(5,341)
44				
45	**Total Jurisdictional Capacity Costs (Line 37+41+43)**	444,991,352	446,437,345	(1,445,993)
46				
47	**True-Up Provision**			
48	True-Up Provision - Over/(Under) Recovered	2,682,780	0	2,682,780
49	Interest Provision for the Month	11,121	0	11,121
50	Current Cycle Balance - Over/(Under)	2,693,901	0	2,693,901
51				
52	Prior Period Balance - Over/(Under) Recovered	15,765,080	16,610,473	(845,393)
53	Prior Period Cumulative True-Up Collected/(Refunded)	(16,610,472)	(16,610,473)	1
54	Prior Period True-up Balance - Over/(Under)	(845,392)	0	(845,392)
55				
56	**Net Capacity True-up Over/(Under) (Line 50+54)**	$1,848,509	$0	$1,848,509

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] Approved in Commission Order No. PSC-2018-0490-FOF-EI.
[3] Approved in Commission Order No. PSC-2016-0425-PAA-EI.

Docket No.20190001-EI
Exhibit No. ____(CAM-3)
Part 1

DUKE ENERGY FLORIDA, LLC

Fuel and Capacity Cost Recovery Factor

January through December 2020

PART 1 – 2020 FUEL PRICE FORECAST ASSUMPTIONS

Projected Market Price by Fuel Type

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 7
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: Christopher Menendez CAM-3

PROJECTED MARKET PRICE BY FUEL TYPE

	Light Oil		Coal Crystal River 4 & 5		Natural Gas
Month	$/barrel	$/mmbtu	$/ton	$/mmbtu	$/mmbtu
Jan 2020	75.48	13.02	72.54	3.08	2.80
Feb 2020	80.01	13.80	72.49	3.08	2.78
Mar 2020	81.68	14.09	72.44	3.07	2.71
Apr 2020	84.59	14.60	72.39	3.06	2.51
May 2020	83.60	14.42	72.34	3.06	2.49
Jun 2020	74.56	12.86	72.28	3.05	2.52
Jul 2020	75.23	12.98	72.18	3.04	2.56
Aug 2020	75.60	13.04	71.62	3.03	2.57
Sep 2020	76.04	13.12	71.25	3.03	2.56
Oct 2020	76.08	13.13	70.80	3.02	2.58
Nov 2020	75.65	13.05	70.63	3.01	2.64
Dec 2020	75.33	13.00	70.64	3.01	2.79
Average	77.82	13.43	71.80	3.05	2.63

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 thrid 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 allow for use of higher sulfur coal.

Natural Gas: The base market natural gas proce 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 2020

PART 2 - 2020 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

(Order No. PSC-12-0425-PAA-EU)

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2020 through December 2020

			DOLLARS	mWh	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)		1,187,595,814	39,901,097	2.9763
2.	Coal Car Investment		0	0	0.0000
3.	Adjustment to Fuel Cost		471,689	0	0.0000
4.	TOTAL COST OF GENERATED POWER		1,188,067,503	39,901,097	2.9775
5.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		40,223,323	1,184,223	3.3966
6.	Energy Cost of Economy Purchases (E9)		2,806,587	71,819	3.9079
7.	Payments to Qualifying Facilities (E8)		117,941,811	2,878,391	4.0975
8.	TOTAL COST OF PURCHASED POWER		160,971,721	4,134,433	3.8934
9.	TOTAL AVAILABLE mWh			44,035,530	
10.	Fuel Cost of Economy Sales	(E6)	(5,181,263)	(151,923)	3.4105
10a.	Gain on Economy Sales	(E6)	(1,371,287)	(151,923) *	0.9026
10b.	Gain on Total Power Sales - 20%	(E6)	0		
11.	Fuel Cost of Stratified Sales	(E6)	(33,865,852)	(1,464,420)	2.3126
12.	TOTAL FUEL COST AND GAINS ON POWER SALES		(40,418,402)	(1,616,343)	2.5006
13.	Net Inadvertent Interchange				
14.	TOTAL FUEL AND NET POWER TRANSACTIONS		1,308,620,822	42,419,187	3.0850
15.	Net Unbilled		(1,157,040) *	3,686	(0.0029)
16.	Company Use		6,324,102 *	(204,320)	0.0159
17.	T & D Losses		78,614,402 *	(2,548,274)	0.1982
18.	Adjusted System Sales		1,308,620,822	39,670,279	3.2962
19.	Wholesale Sales (Excluding Supplemental Sales)		(5,734,171)	(173,703)	3.3011
20.	Jurisdictional Sales		1,302,886,651	39,496,577	3.2987
21.	Jurisdictional Sales Adjusted for Line Losses x	1.00034	1,303,329,632	39,496,577	3.2999
22.	Prior Period True-Up (Sch E1-A)		14,462,684	39,496,577	0.0366
23.	Total Jurisdictional Fuel Cost		1,317,792,316	39,496,577	3.3365
24.	Revenue Tax Factor		948,810		1.0007
25.	Fuel Cost Adjusted for Taxes		1,318,741,126	39,496,577	3.3389
26.	GPIF **		2,591,697	39,496,577	0.0066
27.	Fuel Factor Adjusted for taxes including GPIF		1,321,332,823	39,496,577	3.3454
28.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				3.3450

* 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 2020 through December 2020

1.	Actual Over/(Under) Recovery January - December 2018 **(** Schedule E1-B, Page 2 of 2, Section C, Line 9 - Dec 18 **)**	$	(202,879,590)
2.	Projected (Over)/Under Recovery January - December 2018 (Refunded)/Collected January - December 2019 **(** Schedule E1-B, Page 2 of 2, Section C, Line 10 - Dec 18 **)**	$	148,450,915
3.	Estimated Over/(Under) Recovery January - December 2019 **(** Schedule E1-B, Page 2 of 2, Section C, Line 8 - Dec 19 **)**	$	39,965,991
4.	Total Over/(Under) Recovery (Line 1 through Line 3)	$	(14,462,684)
5.	Jurisdictional mWh Sales (Projected Period)	mWh	39,496,577
6.	True-Up Factor (Line 6 / Line 7)	Cents/kWh	0.037

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

			Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	6 Month Sub-Total
A	1	Fuel Cost of System Generation	$ 109,976,964	$ 82,327,645	$ 91,917,642	$ 96,277,004	$ 109,917,691	$ 118,976,978	$ 609,393,924
	2	Fuel Cost of Power Sold	(3,100,010)	(1,478,546)	(2,257,015)	(2,883,465)	(4,252,385)	(9,623,682)	(23,595,103)
	3	Fuel Cost of Purchased Power	3,709,959	2,648,955	5,132,188	6,247,340	13,339,364	12,829,894	43,907,699
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	10,908,157	7,601,725	7,328,667	7,064,641	8,882,702	9,231,306	51,017,197
	4	Energy Cost of Economy Purchases	184,282	240,158	250,203	378,398	462,113	517,405	2,032,557
	5	Adjustments to Fuel Cost	1,304,334	1,209,489	1,202,751	1,198,907	1,197,017	1,196,947	7,309,445
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	122,983,686	92,549,425	103,574,435	108,282,824	129,546,501	133,128,847	690,065,719
B	1	Jurisdictional mWh Sales	2,669,994	2,719,125	2,780,959	2,897,129	3,185,818	3,813,849	18,066,873
	2	Non-Jurisdictional mWh Sales	19,604	18,678	12,252	12,171	17,654	31,506	111,863
	3	TOTAL SALES (Lines B1 + B2)	2,689,597	2,737,803	2,793,210	2,909,299	3,203,472	3,845,354	18,178,736
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.32%	99.56%	99.58%	99.45%	99.18%	99.38%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	104,760,834	106,246,246	108,046,001	112,815,219	125,936,532	152,625,203	710,430,035
	2	True-Up Provision	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(74,225,460)
	2a	Incentive Provision	191,794	191,794	191,794	191,794	191,794	191,794	1,150,764
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	92,581,718	94,067,130	95,866,885	100,636,103	113,757,416	140,446,087	637,355,339
	4	Fuel & Net Power Transactions (Line A6)	122,983,686	92,549,425	103,574,435	108,282,824	129,546,501	133,128,847	690,065,719
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	122,123,752	91,951,342	103,153,768	107,864,698	128,877,798	132,082,083	686,053,442
	6	Over/(Under) Recovery (Line C3 - Line C5)	(29,542,034)	2,115,788	(7,286,883)	(7,228,595)	(15,120,383)	8,364,004	(48,698,103)
	7	Interest Provision	(422,930)	(428,593)	(415,902)	(408,311)	(398,760)	(371,997)	(2,446,493)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(29,964,965)	1,687,195	(7,702,785)	(7,636,906)	(15,519,143)	7,992,008	(51,144,593)
	9	Plus: Prior Period Balance	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)
	10	Plus: Cumulative True-Up Provision	12,370,910	24,741,820	37,112,730	49,483,640	61,854,550	74,225,460	74,225,460
	11	Subtotal Prior Period True-up	(190,508,680)	(178,137,770)	(165,766,860)	(153,395,950)	(141,025,040)	(128,654,130)	(128,654,130)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($220,473,645)	(206,415,539)	($201,747,415)	($197,013,411)	($200,161,644)	($179,798,727)	(179,798,727)

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

			Jul Estimated	Aug Estimated	Sep Estimated	Oct Estimated	Nov Estimated	Dec Estimated	12 Month Period
A	1	Fuel Cost of System Generation	$ 117,430,448	$ 116,590,525	$ 108,507,217	$ 95,523,571	$ 87,935,869	$ 92,653,910	$ 1,228,035,464
	2	Fuel Cost of Power Sold	(8,107,008)	(8,047,357)	(6,900,753)	(6,494,023)	(3,667,686)	(4,267,921)	(61,079,851)
	3	Fuel Cost of Purchased Power	8,184,838	6,876,582	6,779,581	7,136,160	2,844,662	1,106,770	76,836,292
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	10,332,497	10,289,444	9,155,724	9,742,112	9,860,682	10,026,097	110,423,752
	4	Energy Cost of Economy Purchases	188,238	123,884	128,246	137,662	89,384	223,111	2,923,082
	5	Adjustments to Fuel Cost	1,185,271	1,181,837	1,172,013	1,168,362	1,164,477	1,162,111	14,343,516
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	129,214,284	127,014,915	118,842,028	107,213,844	98,227,388	100,904,077	1,371,482,256
B	1	Jurisdictional mWh Sales	3,840,042	3,872,711	3,972,711	3,626,916	3,055,736	2,878,978	39,313,967
	2	Non-Jurisdictional mWh Sales	36,625	37,341	16,716	14,981	11,631	13,906	243,064
	3	TOTAL SALES (Lines B1 + B2)	3,876,667	3,910,052	3,989,428	3,641,897	3,067,367	2,892,884	39,557,031
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.06%	99.05%	99.58%	99.59%	99.62%	99 52%	99.39%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	152,301,622	153,597,318	157,563,471	143,848,708	121,194,902	114,184,412	1,553,120,468
	2	True-Up Provision	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(148,450,915)
	2a	Incentive Provision	191,794	191,794	191,794	191,794	191,794	191,792	2,301,526
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	140,122,506	141,418,202	145,384,355	131,669,592	109,015,786	102,005,294	1,406,971,079
	4	Fuel & Net Power Transactions (Line A6)	129,214,284	127,014,915	118,842,028	107,213,844	98,227,388	100,904,077	1,371,482,256
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	128,043,189	125,851,048	118,383,128	106,810,571	97,887,395	100,453,881	1,363,482,653
	6	Over/(Under) Recovery (Line C3 - Line C5)	12,079,317	15,567,153	27,001,228	24,859,021	11,128,391	1,551,413	43,488,421
	7	Interest Provision	(328,337)	(277,639)	(212,216)	(137,572)	(78,343)	(41,829)	(3,522,429)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	11,750,980	15,289,514	26,789,011	24,721,449	11,050,048	1,509,584	39,965,991
	9	Plus: Prior Period Balance	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)
	10	Plus: Cumulative True-Up Provision	86,596,370	98,967,280	111,338,190	123,709,100	136,080,010	148,450,915	148,450,915
	11	Subtotal Prior Period True-up	(116,283,220)	(103,912,310)	(91,541,400)	(79,170,490)	(66,799,580)	(54,428,675)	(54,428,675)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($155,676,837)	($128,016,412)	($88,856,491)	($51,764,131)	($28,343,173)	($14,462,684)	(14,462,684)

Duke Energy Florida, LLC
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period of : January 2020 through December 2020

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	2,591,697
	B. True-Up (Over) / Under Recovery	$	14,462,684
2.	JURISDICTIONAL mWh SALES	mWh	39,496,577
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	Cents/kWh	0.007
	B. True-Up Factor	Cents/kWh	0.037

Duke Energy Florida, LLC
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January 2020 through December 2020

1.	Period Jurisdictional Fuel Cost (Schedule E-1, line 21)	$	1,303,329,632	
1a.	Prior Period True-up (E1, Line 22)	$	14,462,684	
2.	Regulatory Assessment Fee (E1, Line 24)	$	948,810	
3.	Generating Performance Incentive Factor (GPIF) (E1, Line 26)	$	2,591,697	
4.	Total Amount to be Recovered	$	1,321,332,823	
5.	Jurisdictional Sales (January - December 2018)		39,496,577	mWh
6.	Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)		3.345	Cents/kWh
7.	Effective Jurisdictional Sales (See Below)		39,448,649	mWh
	LEVELIZED FUEL FACTORS:			
8.	Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)		3 350	Cents/kWh
9.	Fuel Factor at Primary Metering		3 317	Cents/kWh
10.	Fuel Factor at Transmission Metering		3 283	Cents/kWh
	TIERED FUEL FACTORS:			
11	Fuel Factor - First Tier (0-1000 kWh)		3 067	Cents/kWh
12	Fuel Factor - Second Tier (Over 1000 kWh)		4 067	Cents/kWh

	JURISDICTIONAL SALES (mWh)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	35,126,666	35,126,666
Distribution Primary	3,947,238	3,907,765
Transmission	422,672	414,219
Total	39,496,575	39,448,649

Duke Energy Florida, LLC
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January 2020 through December 2020

Line:	Metering Voltage	First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	----------Time of Use---------- On-Peak Multiplier 1.286	Off-Peak Multiplier 0.872
1.	Distribution Secondary	3.067	4.067	3.350	4.308	2.921
2.	Distribution Primary	--	--	3.317	4.266	2.892
3.	Transmission	--	--	3.283	4.222	2.863
4.	Lighting Service	--	--	3.181	--	--

Line 4 calculated at secondary rate of 3.35 * (18.7% * On-Peak Multiplier 1.286 + 81.3% * Off-Peak Multiplier 0.872).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			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)
Jan-20	831,111	26,096,881	3.140	2,285,773	47,666,695	2.085	3,116,884	73,763,575	2.367
Feb-20	737,927	21,148,521	2.866	2,074,294	44,830,901	2.161	2,812,221	65,979,422	2.346
Mar-20	748,622	21,061,779	2.813	2,134,190	49,839,412	2.335	2,882,812	70,901,191	2.459
Apr-20	1,030,076	33,358,419	3.238	1,934,611	40,302,310	2.083	2,964,687	73,660,730	2.485
May-20	1,157,230	37,917,718	3.277	2,491,719	50,596,271	2.031	3,648,949	88,513,989	2.426
Jun-20	1,399,153	47,216,521	3.375	2,584,527	54,358,193	2.103	3,983,680	101,574,714	2.550
Jul-20	1,510,372	51,305,802	3.397	2,786,095	60,102,243	2.157	4,296,467	111,408,045	2.593
Aug-20	1,358,882	45,848,953	3.374	2,862,504	62,742,269	2.192	4,221,385	108,591,222	2.572
Sep-20	1,326,682	44,763,399	3.374	2,626,255	56,105,858	2.136	3,952,937	100,869,257	2.552
Oct-20	1,134,314	34,673,222	3.057	2,268,608	49,200,574	2.169	3,402,921	83,873,796	2.465
Nov-20	666,585	18,451,074	2.768	2,093,555	48,646,134	2.324	2,760,140	67,097,207	2.431
Dec-20	795,262	23,111,134	2.906	2,246,984	49,384,142	2.198	3,042,246	72,495,276	2.383
TOTAL	12,696,216	404,953,422	3.190	28,389,114	613,775,001	2.162	41,085,330	1,018,728,424	2.480

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST			
WEIGHTING MULTIPLIER	1 286	0.872	1.000

Duke Energy Florida, LLC
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2018
Estimated for the Period of : January 2020 through December 2020

		Energy Delivered @ Billing Level							
		Billed mWh	Unbilled mWh	Total mWh	% of Total	Delivery Efficiency	Energy Required @ Source Level	% of Total	Jurisdictional Loss Multiplier
Retail									
Transmission		397,952	305	398,257		0.9835768	404,907		
Distribution Primary		3,815,488	2,926	3,818,414		0.9735768	3,922,046		
Distribution Secondary		34,931,209	26,789	34,957,998		0.9356728	37,361,348		
Total Retail		39,144,649	30,020	39,174,669	99.42%	0.9397041	41,688,302	99.45%	1.00034
						6.03%			
Wholesale									
Generation Level		203,623	-	203,623		1.0000000	203,623		
Transmission		-	-	-		0.9835768	-		
Distribution Primary		26,582	-	26,582		0.9735768	27,304		
Distribution Secondary		-	-	-			-		
Total Wholesale		230,206	-	230,206	0.58%	0.9968758	230,927	0.55%	0.94297
						0.31%			
Subtotal Class		39,374,854	30,020	39,404,874	100.00%	0.9400191	41,919,229	100.00%	1.00000
						6.00%			
Non-Class									
SEPA	Transmission	23,968	-	23,968		0.9835768	24,368		
Homestead Base & Int	Generation	30,762	-	30,762		1.0000000	30,762		
SECI - CC	Generation	714,558	-	714,558		1.0000000	714,558		
SECI - Base	Generation	85,075	-	85,075		1.0000000	85,075		
Reedy Creek Base & Int	Generation	556,716	-	556,716		1.0000000	556,716		
Reedy Creek Hines	Generation	463,792	-	463,792		1.0000000	463,792		
NSB - Peaking	Generation	-	-	-		1.0000000	-		
SECI - Intermediate	Generation	163,204	-	163,204		1.0000000	163,204		
SECI - Peaking	Generation	55,834	-	55,834		1.0000000	55,834		
Interchange	Generation	9,482	-	9,482		1.0000000	9,482		
Company Use	Secondary	187,431	-	187,431		0.9356728	200,317		
Total Non-Class		2,290,822	-	2,290,822			2,304,108		
Total System		41,665,676	30,020	41,695,696		0.942844	44,223,337		

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2020 through December 2020

			Estimated Jan-20	Estimated Feb-20	Estimated Mar-20	Estimated Apr-20	Estimated May-20	Estimated Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	TOTAL
1	Fuel Cost of System Net Generation		$95,208,052	$86,395,218	$87,571,762	$83,811,579	$102,982,305	$108,663,879	$117,244,609	$117,296,374	$109,660,562	$100,553,338	$86,382,625	$91,825,511	$1,187,595,814
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(12,033,183)	1,153,763	1,150,462	1,147,044	1,144,775	1,141,008	1,137,129	1,133,480	1,129,604	1,125,957	1,122,085	1,119,564	471,689
2	Fuel Cost of Power Sold		(968,364)	(383,926)	(150,964)	(167,780)	(436,720)	(435,481)	(628,970)	(802,288)	(337,749)	(263,633)	(169,717)	(435,671)	(5,181,263)
2a	Gains on Power Sales		(256,290)	(101,610)	(39,954)	(44,406)	(115,584)	(115,255)	(166,465)	(212,336)	(89,390)	(69,774)	(44,918)	(115,305)	(1,371,287)
2b	Fuel Cost of Stratified Sales		(4,705,071)	(3,745,252)	(2,144,160)	(3,091,043)	(2,868,019)	(3,236,996)	(3,548,561)	(3,160,893)	(2,579,263)	(2,080,583)	(1,077,352)	(1,628,658)	(33,865,852)
3	Fuel Cost of Purchased Power (Excl Economy)		1,104,453	1,066,887	3,706,922	2,804,334	2,971,297	5,675,595	6,833,935	5,299,790	5,264,298	2,886,897	1,282,745	1,326,170	40,223,323
3a	Energy Payments to Qualifying Facilities		10,321,439	9,611,794	9,464,477	9,623,406	10,104,514	9,810,413	10,233,157	10,251,146	9,613,299	8,465,057	9,877,229	10,565,880	117,941,811
4	Energy Cost of Economy Purchases		232,265	251,357	330,864	329,067	201,399	164,565	184,692	157,157	196,292	184,665	276,466	297,798	2,806,587
5	Total System Fuel & Net Power Transactions		$88,903,301	$94,248,232	$99,889,408	$94,412,201	$113,983,967	$121,667,728	$131,289,525	$129,962,429	$122,857,653	$110,801,924	$97,649,163	$102,955,289	$1,308,620,822
6	Jurisdictional mWh Sold		3,046,934	2,851,309	2,713,732	2,759,453	2,960,871	3,602,477	3,872,304	4,088,899	3,980,798	3,683,169	3,018,516	2,918,116	39,496,577
7	Jurisdictional % of Total Sales		99.52%	99.63%	99.61%	99.60%	99.49%	99.51%	99.54%	99.55%	99.58%	99.59%	99.62%	99.53%	99.56%
8	Jurisdicitonal Fuel & Net Power Transactions		88,476,565	93,899,514	99,499,839	94,034,552	113,402,649	121,071,556	130,685,593	129,377,598	122,341,651	110,347,637	97,278,096	102,471,399	1,302,886,651
9	Jurisdictional Loss Multiplier		1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034
10	Jurisdictional Fuel & Net Power Transactions		88,506,647	93,931,440	99,533,669	94,066,524	113,441,206	121,112,721	130,730,026	129,421,587	122,383,247	110,385,155	97,311,171	102,506,240	1,303,329,632
11	Adjusted System Sales	mWh	3,061,479	2,861,919	2,724,264	2,770,608	2,976,077	3,620,236	3,890,277	4,107,587	3,997,514	3,698,150	3,030,146	2,932,022	39,670,279
12	System Cost per kWh Sold	c/kWh	2.9039	3.2932	3.6667	3.4076	3.8300	3.3608	3.3748	3.1640	3.0734	2.9961	3.2226	3.5114	3.2987
13	Jurisdictional Loss Multiplier	x	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034	1.00034
14	Jurisdictional Cost per kWh Sold	c/kWh	2.9048	3.2943	3.6678	3.4089	3.8313	3.3619	3.3760	3.1652	3.0743	2.9970	3.2238	3.5128	3.2999
15	Prior Period True-Up	+	0.0396	0.0423	0.0444	0.0437	0.0407	0.0335	0.0311	0.0295	0.0303	0.0327	0.0399	0.0413	0.0366
16	Total Jurisdictional Fuel Expense	c/kWh	2.9443	3.3366	3.7122	3.4526	3.8721	3.3954	3.4071	3.1947	3.1046	3.0297	3.2637	3.5541	3.3365
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	2.9465	3.3390	3.7149	3.4550	3.8748	3.3978	3.4096	3.1970	3.1069	3.0319	3.2661	3.5566	3.3389
19	GPIF	+	0.0071	0.0076	0.0080	0.0078	0.0073	0.0060	0.0056	0.0053	0.0054	0.0059	0.0072	0.0074	0.0066
20	Total Recovery Factor (rounded .001)	c/kWh	2.954	3.347	3.723	3.463	3.882	3.404	3.415	3.202	3.112	3.038	3.273	3.564	3.345

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2020 through December 2020

			Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		92,118	108,601	145,750	134,827	192,303	142,056	815,655
2	COAL		5,552,605	3,307,188	6,028,153	4,200,293	10,565,344	13,063,992	42,717,575
3	GAS		89,563,329	82,979,429	81,397,859	79,476,459	92,224,658	95,457,831	521,099,565
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	95,208,052	86,395,218	87,571,762	83,811,579	102,982,305	108,663,879	564,632,795
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		31	16	51	39	0	0	136
7	COAL		77,832	7,660	91,123	36,219	226,125	306,760	745,719
8	GAS		2,974,926	2,738,525	2,632,950	2,751,738	3,239,030	3,410,712	17,747,881
9	SOLAR		34,993	38,936	49,366	91,963	98,609	89,105	402,972
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	3,087,782	2,785,137	2,773,489	2,879,959	3,563,764	3,806,577	18,896,708
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	78	269	698	551	1,211	712	3,519
13	COAL	TON	34,402	3,452	41,015	16,485	104,488	139,134	338,976
14	GAS	MCF	20,877,664	19,239,554	18,750,664	19,762,609	23,442,457	24,860,339	126,933,287
15	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		453	1,566	4,062	3,202	7,055	4,150	20,488
17	COAL		809,485	81,336	967,618	389,412	2,471,504	3,295,480	8,014,835
18	GAS		20,877,664	19,239,554	18,750,664	19,762,609	23,442,457	24,860,339	126,933,287
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	21,687,602	19,322,456	19,722,344	20,155,223	25,921,016	28,159,969	134,968,610
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22	COAL		2.52%	0.28%	3.29%	1.26%	6.35%	8.06%	3.95%
23	GAS		96.35%	98.33%	94.93%	95.55%	90.89%	89.60%	93.92%
24	SOLAR		1.13%	1.40%	1.78%	3.19%	2.77%	2.34%	2.13%
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	1181.00	403.72	208.81	244.70	158.80	199.52	231.79
28	COAL	$/TON	161.40	958.05	146.97	254.79	101.12	93.90	126.02
29	GAS	$/MCF	4.29	4.31	4.34	4.02	3.93	3.84	4.11
30	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
31	LIGHT OIL		203.35	69.35	35.88	42.11	27.26	34.23	39.81
32	COAL		6.86	40.66	6.23	10.79	4.28	3.96	5.33
33	GAS		4.29	4.31	4.34	4.02	3.93	3.84	4.11
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	4.39	4.47	4.44	4.16	3.97	3.86	4.18
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		14,852	97,875	80,277	82,103	0	0	150,536
37	COAL		10,400	10,618	10,619	10,752	10,930	10,743	10,748
38	GAS		7,018	7,026	7,122	7,182	7,237	7,289	7,152
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,024	6,938	7,111	6,998	7,273	7,398	7,142
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		302.03	678.76	288.04	345.71	0.00	0.00	599.31
42	COAL		7.13	43.17	6.62	11.60	4.67	4.26	5.73
43	GAS		3.01	3.03	3.09	2.89	2.85	2.80	2.94
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	3.08	3.10	3.16	2.91	2.89	2.85	2.99

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2020 through December 2020

			Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		193,424	128,183	146,749	229,530	121,878	87,554	1,722,973
2	COAL		16,466,819	14,080,933	12,341,927	15,656,950	10,250,591	3,006,948	114,521,743
3	GAS		100,584,366	103,087,258	97,171,886	84,666,858	76,010,156	88,731,009	1,071,351,098
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	117,244,609	117,296,374	109,660,562	100,553,338	86,382,625	91,825,511	1,187,595,814
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		0	10	19	3	7	6	181
7	COAL		413,388	343,481	289,499	389,701	225,047	0	2,406,835
8	GAS		3,595,598	3,631,928	3,426,980	2,853,995	2,439,341	2,957,257	36,652,981
9	SOLAR		87,177	84,489	76,710	75,236	61,202	53,315	841,101
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	4,096,163	4,059,908	3,793,208	3,318,935	2,725,597	3,010,578	39,901,097
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	1,353	529	757	1,789	450	20	8,417
13	COAL	TON	186,466	154,619	131,014	178,665	102,561	0	1,092,301
14	GAS	MCF	26,177,178	26,814,233	25,175,172	20,882,569	17,511,395	20,662,911	264,156,745
15	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		7,885	3,081	4,415	10,423	2,620	115	49,027
17	COAL		4,421,050	3,649,019	3,083,981	4,188,503	2,403,629	0	25,761,017
18	GAS		26,177,178	26,814,233	25,175,172	20,882,569	17,511,395	20,662,911	264,156,745
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	30,606,113	30,466,333	28,263,568	25,081,495	19,917,644	20,663,026	289,966,789
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22	COAL		10.09%	8.46%	7.63%	11.74%	8.26%	0.00%	6.03%
23	GAS		87.78%	89.46%	90.35%	85.99%	89.50%	98.23%	91.86%
24	SOLAR		2.13%	2.08%	2.02%	2.27%	2.25%	1.77%	2.11%
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	142.96	242.31	193.86	128.30	270.84	4377.70	204.70
28	COAL	$/TON	88.31	91.07	94.20	87.63	99.95	0.00	104.84
29	GAS	$/MCF	3.84	3.84	3.86	4.05	4.34	4.29	4.06
30	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
31	LIGHT OIL		24.53	41.60	33.24	22.02	46.52	761.34	35.14
32	COAL		3.73	3.86	4.00	3.74	4.27	0.00	4.45
33	GAS		3.84	3.84	3.86	4.05	4.34	4.29	4.06
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	3.83	3.85	3.88	4.01	4.34	4.44	4.10
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		0	308,100	232,368	3,474,333	374,286	19,167	270,718
37	COAL		10,695	10,624	10,653	10,748	10,681	0	10,703
38	GAS		7,280	7,383	7,346	7,317	7,179	6,987	7,207
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,472	7,504	7,451	7,557	7,308	6,863	7,267
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		0.00	1281.83	772.36	7651.00	1741.11	1459.23	951.39
42	COAL		3.98	4.10	4.26	4.02	4.55	0.00	4.76
43	GAS		2.80	2.84	2.84	2.97	3.12	3.00	2.92
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	2.86	2.89	2.89	3.03	3.17	3.05	2.98

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jan-20

	(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	36,410	6.7	85.61	57.8	10,412	COAL	16,111 TONS	23.53	379,088	2,697,210	7.41
2	CRYSTAL RIVER 5	712	41,422	7.8	93.00	55.4	10,391	COAL	18,291 TONS	23.53	430,397	2,855,395	6.89
3	ANCLOTE 1	517	5,930	1.5	97.10	22.9	11,403	GAS	67,623 MCF	1.00	67,623	280,483	4.73
4	ANCLOTE 2	521	1,254	0.3	95.48	34.4	11,262	GAS	14,118 MCF	1.00	14,118	130,506	10.41
5	AVON PARK 1-2	69	0	0.0	93.83	0.0	0	GAS	0 MCF	0.00	0	0	0.00
6	BARTOW 1-4	228	163	0.1	85.40	0.0	14,997	GAS	2,449 MCF	1.00	2,449	11,664	7.14
7	BARTOW CC 1	1279	539,025	56.6	96.77	58.5	7,664	GAS	4,130,941 MCF	1.00	4,130,941	17,404,171	3.23
8	CITRUS CC 1-2	1640	1,223,054	100 2	97.74	103.1	6,501	GAS	7,950,544 MCF	1.00	7,950,544	34,116,066	2.79
9	DEBARY 1-10	785	3,006	0.5	91.78	9.1	13,274	GAS	39,901 MCF	1.00	39,901	183,812	6.11
10	HIGGINS 1-4	129	111	0.1	64.53	28.8	15,566	GAS	1,734 MCF	1.00	1,734	8,994	8.07
11	HINES CC 1-4	2,204	955,805	58.3	96.21	83.9	7,031	GAS	6,720,326 MCF	1.00	6,720,326	28,955,808	3.03
12	INT CITY 1-14	1,186	3,792	0.4	94.22	7.6	12,483	GAS	47,336 MCF	1.00	47,336	212,425	5.60
13	OSPREY CC 1	505	181,745	48.4	96.89	54.9	7,503	GAS	1,363,687 MCF	1.00	1,363,687	5,946,159	3.27
14	SUWANNEE CT 1-3	200	3,236	2.2	86.49	23.1	14,095	GAS	45,616 MCF	1.00	45,616	207,593	6.41
15	TIGER BAY CC 1	225	24,684	14.7	95.81	100.6	7,429	GAS	183,382 MCF	1.00	183,382	744,480	3.02
16	UNIV OF FLA. CC 1	47	33,120	94.7	96.83	97.9	9,360	GAS	310,007 MCF	1.00	310,007	1,361,168	4.11
17	AVON PARK 1-2	69	0	0.0	93.83	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
18	BARTOW 1-4	228	0	0.0	85.40	0.0	0	LIGHT OIL	0 BBLS	0.00	0	178	0.00
19	BAYBORO 1-4	231	0	0.0	88.88	0.0	0	LIGHT OIL	0 BBLS	0.00	0	88	0.00
20	DEBARY 1-10	785	0	0.0	91.78	0.0	0	LIGHT OIL	0 BBLS	0.00	0	654	0.00
21	HIGGINS 1-4	129	0	0.0	64.53	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
22	OTHER	0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23	INT CITY 1-14	1,186	31	0.4	94.22	2.6	14,852	LIGHT OIL	78 BBLS	5.81	453	10,138	33.24
24	SUWANNEE 1-3	200	0	0.0	86.49	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
25	OTHER & START UP	-	0	-	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	81,060	0.00
26	SOLAR	241	34,993	19.5	0.00	43.1	0	SOLAR	0 N/A		0	0	0.00
27	TOTAL		3,087,782								21,687,602	95,208,052	3.08

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Feb-20

(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	0	0.0	90 02	0.0	0	COAL	0 TONS	0.00	0	1,528,474	0.00
2 CRYSTAL RIVER	5	712	7,660	1.5	94.44	46.8	10,618	COAL	3,452 TONS	23.56	81,336	1,778,714	23.22
3 ANCLOTE	1	517	0	0.0	95.17	0.0	0	GAS	0 MCF	0.00	0	41,095	0.00
4 ANCLOTE	2	521	0	0.0	97 59	0.0	0	GAS	0 MCF	0.00	0	41,095	0.00
5 AVON PARK	1-2	69	10	0.0	94 04	0.0	18,100	GAS	181 MCF	1.00	181	507	5.07
6 BARTOW	1-4	228	169	0.1	86 26	15.1	15,801	GAS	2,664 MCF	1.00	2,664	12,341	7.32
7 BARTOW CC	1	1279	496,929	55.8	97 24	57.4	7,681	GAS	3,816,703 MCF	1.00	3,816,703	16,173,545	3.25
8 CITRUS CC	1-2	1640	1,102,669	96.6	95 52	102.0	6,493	GAS	7,159,778 MCF	1.00	7,159,778	30,865,284	2.80
9 DEBARY	1-10	785	2,942	0.5	91.40	8.7	13,413	GAS	39,455 MCF	1.00	39,455	180,841	6.15
10 HIGGINS	1-4	129	152	0.2	64.79	29.5	15,618	GAS	2,374 MCF	1.00	2,374	12,632	8.31
11 HINES CC	1-4	2,204	904,255	58.9	97 59	81.6	7,058	GAS	6,382,619 MCF	1.00	6,382,619	27,582,483	3.05
12 INT CITY	1-14	1,186	2,890	0.4	92 91	7.6	12,563	GAS	36,304 MCF	1.00	36,304	163,150	5.65
13 OSPREY CC	1	505	157,626	44.8	93.16	55.0	7,542	GAS	1,188,878 MCF	1.00	1,188,878	5,185,281	3.29
14 SUWANNEE CT	1-3	200	3,323	2.4	87 59	23.4	14,024	GAS	46,597 MCF	1.00	46,597	204,204	6.15
15 TIGER BAY CC	1	225	36,318	23.2	95 24	99.0	7,480	GAS	271,673 MCF	1.00	271,673	1,225,761	3.38
16 UNIV OF FLA. CC	1	47	31,243	95.5	97 55	97.9	9,357	GAS	292,328 MCF	1.00	292,328	1,291,210	4.13
17 AVON PARK	1-2	69	0	0.0	94 04	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
18 BARTOW	1-4	228	3	0.1	86 26	0.0	23,000	LIGHT OIL	12 BBLS	5.75	69	1,167	38.90
19 BAYBORO	1-4	231	0	0.0	91 20	0.0	0	LIGHT OIL	0 BBLS	0.00	0	88	0.00
20 DEBARY	1-10	785	4	0.5	91.40	0.0	20,500	LIGHT OIL	14 BBLS	5.86	82	1,836	45.90
21 HIGGINS	1-4	129	0	0.0	64.79	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
22 OTHER		0	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23 INT CITY	1-14	1,186	6	0.4	92 91	0.0	17,500	LIGHT OIL	18 BBLS	5.83	105	5,514	91.90
24 SUWANNEE	1-3	200	3	2.4	87 59	0.0	21,667	LIGHT OIL	11 BBLS	5.91	65	948	31.60
25 OTHER & START UP		-	0	-	0 00	0.0	0	LIGHT OIL	214 BBLS	5.82	1,245	99,048	0.00
26 SOLAR		241	38,936	23.2	0 00	50.5	0	SOLAR	0 N/A		0	0	0.00
27 TOTAL			2,785,137								19,322,456	86,395,218	3.10

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Mar-20

(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	0	0.0	0.00	0.0	0	COAL	0 TONS	0.00	0	1,528,474	0.00
2 CRYSTAL RIVER	5	712	91,123	17.2	91.94	57.9	10,619	COAL	41,015 TONS	23.59	967,618	4,499,679	4.94
3 ANCLOTE	1	517	51,776	13.5	92.90	28.1	11,197	GAS	579,707 MCF	1.00	579,707	1,981,120	3.83
4 ANCLOTE	2	521	3,947	1.0	98.06	25.3	12,047	GAS	47,546 MCF	1.00	47,546	542,155	13.74
5 AVON PARK	1-2	69	12	0.0	92.68	17.4	25,833	GAS	310 MCF	1.00	310	838	6.98
6 BARTOW	1-4	228	217	0.1	84.00	19.1	14,066	GAS	3,058 MCF	1.00	3,058	15,895	7.31
7 BARTOW CC	1	1279	488,727	51.4	92.58	55.5	7,656	GAS	3,741,773 MCF	1.00	3,741,773	15,544,151	3.18
8 CITRUS CC	1-2	1640	1,071,747	87.8	95.65	92.4	6,527	GAS	6,994,867 MCF	1.00	6,994,867	31,164,201	2.91
9 DEBARY	1-10	785	6,539	1.1	92.41	8.2	13,224	GAS	86,475 MCF	1.00	86,475	384,591	5.88
10 HIGGINS	1-4	129	109	0.1	64.71	21.1	16,688	GAS	1,814 MCF	1.00	1,814	6,510	5.99
11 HINES CC	1-4	2,204	929,889	56.7	74.35	73.7	7,108	GAS	6,609,479 MCF	1.00	6,609,479	28,843,208	3.10
12 INT CITY	1-14	1,186	5,304	0.6	79.30	6.0	12,845	GAS	68,125 MCF	1.00	68,125	294,163	5.55
13 OSPREY CC	1	505	53,167	14.2	37.46	67.5	7,666	GAS	407,559 MCF	1.00	407,559	1,676,027	3.15
14 SUWANNEE CT	1-3	200	1,664	1.1	87.15	20.8	14,292	GAS	23,777 MCF	1.00	23,777	96,210	5.78
15 TIGER BAY CC	1	225	0	0.0	100.00	0.0	0	GAS	0 MCF	0.00	0	0	0.00
16 UNIV OF FLA. CC	1	47	19,853	56.8	94.08	93.7	9,378	GAS	186,174 MCF	1.00	186,174	848,790	4.28
17 AVON PARK	1-2	69	0	0.0	92.68	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
18 BARTOW	1-4	228	0	0.0	84.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	178	0.00
19 BAYBORO	1-4	231	3	0.0	91.05	0.0	18,667	LIGHT OIL	10 BBLS	5.60	56	904	30.13
20 DEBARY	1-10	785	0	0.0	92.41	0.0	0	LIGHT OIL	0 BBLS	0.00	0	654	0.00
21 HIGGINS	1-4	129	0	0.0	64.71	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
22 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23 INT CITY	1-14	1,186	48	0.6	79.30	4.0	14,412	LIGHT OIL	118 BBLS	5.81	686	14,030	29.47
24 SUWANNEE	1-3	200	0	0.0	87.15	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
25 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	570 BBLS	5.82	3,320	129,984	0.00
26 SOLAR		241	49,366	27.5	0.00	54.5	0	SOLAR	0 N/A		0	0	0.00
27 TOTAL			2,773,489								19,722,344	87,571,762	3.16

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Apr-20

	(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	0	0.0	0.00	0.0	0	COAL	0	TONS	0.00	0	1,503,474	0.00
2	CRYSTAL RIVER	5	712	36,219	7.1	93.68	52.4	10,752	COAL	16,485	TONS	23.62	389,412	2,696,819	7.45
3	ANCLOTE	1	517	16,952	4.6	53.73	25.2	11,393	GAS	193,131	MCF	1.00	193,131	482,827	2.85
4	ANCLOTE	2	521	0	0.0	54.91	0.0	0	GAS	0	MCF	0.00	0	0	0.00
5	AVON PARK	1-2	69	0	0.0	93.15	0.0	0	GAS	0	MCF	0.00	0	0	0.00
6	BARTOW	1-4	228	175	0.1	84.50	15.6	14,886	GAS	2,611	MCF	1.00	2,611	8,473	4.83
7	BARTOW CC	1	1279	597,582	64.9	95.67	67.8	7,698	GAS	4,600,250	MCF	1.00	4,600,250	18,247,667	3.05
8	CITRUS CC	1-2	1640	1,066,377	90.3	97.17	93.6	6,540	GAS	6,974,383	MCF	1.00	6,974,383	28,708,625	2.69
9	DEBARY	1-10	785	8,529	1.5	91.79	6.7	14,264	GAS	121,659	MCF	1.00	121,659	427,131	5.01
10	HIGGINS	1-4	129	141	0.2	65.97	21.8	15,842	GAS	2,229	MCF	1.00	2,229	10,332	7.34
11	HINES CC	1-4	2,204	851,098	53.6	72.57	78.8	7,205	GAS	6,132,560	MCF	1.00	6,132,560	24,768,040	2.91
12	INT CITY	1-14	1,186	8,030	0.9	85.84	5.3	13,475	GAS	108,204	MCF	1.00	108,204	374,066	4.66
13	OSPREY CC	1	505	121,138	33.3	85.53	86.9	7,778	GAS	942,160	MCF	1.00	942,160	3,670,144	3.03
14	SUWANNEE CT	1-3	200	2,594	1.8	88.03	21.3	14,402	GAS	37,364	MCF	1.00	37,364	139,973	5.40
15	TIGER BAY CC	1	225	51,243	31.6	94.29	86.6	7,545	GAS	386,650	MCF	1.00	386,650	1,533,763	2.99
16	UNIV OF FLA. CC	1	47	27,878	82.4	97.74	93.6	9,377	GAS	261,408	MCF	1.00	261,408	1,105,418	3.97
17	AVON PARK	1-2	69	0	0.0	93.15	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
18	BARTOW	1-4	228	3	0.1	84.50	0.0	22,333	LIGHT OIL	12	BBLS	5.58	67	1,192	39.73
19	BAYBORO	1-4	231	0	0.0	90.68	0.0	0	LIGHT OIL	0	BBLS	0.00	0	88	0.00
20	DEBARY	1-10	785	24	1.5	91.79	3.1	18,750	LIGHT OIL	78	BBLS	5.77	450	7,552	31.47
21	HIGGINS	1-4	129	0	0.0	65.97	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
22	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
23	INT CITY	1-14	1,186	9	0.9	85.84	0.0	16,111	LIGHT OIL	25	BBLS	5.80	145	6,213	69.03
24	SUWANNEE	1-3	200	3	1.8	88.03	0.0	16,667	LIGHT OIL	9	BBLS	5.56	50	777	25.90
25	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	427	BBLS	5.83	2,490	119,005	0.00
26	SOLAR		316	91,963	40.4	0.00	74.8	0	SOLAR	0	N/A		0	0	0.00
27	TOTAL			2,879,959									20,155,223	83,811,579	2.91

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: May-20

(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	226,125	41 5	84.19	48.7	10,930	COAL	104,488	TONS	23.65	2,471,504	9,061,870	4.01
2 CRYSTAL RIVER	5	712	0	0 0	89.14	0 0	0	COAL	0	TONS	0.00	0	1,503,474	0.00
3 ANCLOTE	1	517	42,202	11 0	42.30	25 0	11,486	GAS	484,731	MCF	1.00	484,731	1,576,130	3.73
4 ANCLOTE	2	521	0	0 0	25.70	0 0	0	GAS	0	MCF	0.00	0	374,482	0.00
5 AVON PARK	1-2	69	0	0 0	93.31	0 0	0	GAS	0	MCF	0.00	0	0	0.00
6 BARTOW	1-4	228	45	0 0	84.42	9 9	14,845	GAS	671	MCF	1.00	671	2,037	4.51
7 BARTOW CC	1	1279	646,959	68 0	97.42	69 8	7,708	GAS	4,986,832	MCF	1.00	4,986,832	19,083,035	2.95
8 CITRUS CC	1-2	1640	1,127,733	92.4	97.42	95 2	6,535	GAS	7,369,175	MCF	1.00	7,369,175	29,111,052	2.58
9 DEBARY	1-10	785	7,829	1 3	68.01	7.6	13,720	GAS	107,410	MCF	1.00	107,410	436,254	5.57
10 HIGGINS	1-4	129	125	0.1	64.54	24.1	15,590	GAS	1,941	MCF	1.00	1,941	9,755	7.84
11 HINES CC	1-4	2,204	1,135,408	69 2	97.20	76.7	7,263	GAS	8,246,505	MCF	1.00	8,246,505	32,646,816	2.88
12 INT CITY	1-14	1,186	7,718	0 9	94.04	5 9	13,173	GAS	101,671	MCF	1.00	101,671	412,554	5.35
13 OSPREY CC	1	505	148,101	39.4	95.59	94 0	7,773	GAS	1,151,143	MCF	1.00	1,151,143	4,557,669	3.08
14 SUWANNEE CT	1-3	200	1,575	1.1	87.99	23 9	13,808	GAS	21,743	MCF	1.00	21,743	91,878	5.83
15 TIGER BAY CC	1	225	89,234	53 3	93.55	87.4	7,509	GAS	670,024	MCF	1.00	670,024	2,703,272	3.03
16 UNIV OF FLA. CC	1	47	32,102	91 8	98.06	93.6	9,364	GAS	300,611	MCF	1.00	300,611	1,219,724	3.80
17 AVON PARK	1-2	69	0	0 0	93.31	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
18 BARTOW	1-4	228	0	0 0	84.42	0 0	0	LIGHT OIL	0	BBLS	0.00	0	178	0.00
19 BAYBORO	1-4	231	0	0 0	89.73	0 0	0	LIGHT OIL	0	BBLS	0.00	0	88	0.00
20 DEBARY	1-10	785	0	0 0	68.01	0 0	0	LIGHT OIL	0	BBLS	0.00	0	654	0.00
21 HIGGINS	1-4	129	0	0 0	64.54	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
22 OTHER		0	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
23 INT CITY	1-14	1,186	0	0 0	94.04	0 0	0	LIGHT OIL	0	BBLS	0.00	0	4,018	0.00
24 SUWANNEE	1-3	200	0	0 0	87.99	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
25 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,211	BBLS	5.83	7,055	187,365	0.00
26 SOLAR		316	98,609	41 9	0.00	77.4	0	SOLAR	0	N/A		0	0	0.00
27 TOTAL			3,563,764									25,921,016	102,982,305	2.89

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jun-20

(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	275,912	52.4	94.56	55.1	10,756	COAL	125,296 TONS	23.69	2,967,710	10,560,240	3 83
2 CRYSTAL RIVER	5	712	30,848	6.0	93.72	57.8	10,625	COAL	13,838 TONS	23.69	327,770	2,503,752	8.12
3 ANCLOTE	1	517	93,600	25.1	93.00	27.0	11,277	GAS	1,055,494 MCF	1.00	1,055,494	3,354,667	3 58
4 ANCLOTE	2	521	2,565	0.7	98.00	35.2	11,794	GAS	30,249 MCF	1.00	30,249	772,075	30.10
5 AVON PARK	1-2	69	0	0.0	48.17	0.0	0	GAS	0 MCF	0.00	0	0	0 00
6 BARTOW	1-4	228	107	0.1	85.57	23.5	14,291	GAS	1,532 MCF	1.00	1,532	5,989	5 59
7 BARTOW CC	1	1279	639,417	69.4	94.67	73.3	7,711	GAS	4,930,677 MCF	1.00	4,930,677	18,476,819	2 89
8 CITRUS CC	1-2	1640	1,122,478	95.1	98.00	97.2	6,524	GAS	7,323,115 MCF	1.00	7,323,115	28,254,279	2 52
9 DEBARY	1-10	785	10,744	1.9	81.83	9.6	12,948	GAS	139,111 MCF	1.00	139,111	511,096	4.76
10 HIGGINS	1-4	129	0	0.0	0.00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
11 HINES CC	1-4	2,204	1,208,674	76.2	96.34	80.0	7,216	GAS	8,721,604 MCF	1.00	8,721,604	33,727,282	2.79
12 INT CITY	1-14	1,186	10,549	1.2	94.27	6.4	12,873	GAS	135,797 MCF	1.00	135,797	499,963	4.74
13 OSPREY CC	1	505	180,752	49.7	95.95	89.9	7,677	GAS	1,387,614 MCF	1.00	1,387,614	5,368,261	2 97
14 SUWANNEE CT	1-3	200	2,800	1.9	88.11	25.0	13,591	GAS	38,049 MCF	1.00	38,049	147,325	5 26
15 TIGER BAY CC	1	225	108,192	66.8	95.33	88.6	7,471	GAS	808,279 MCF	1.00	808,279	3,195,112	2 95
16 UNIV OF FLA. CC	1	47	30,835	91.1	97.30	93.6	9,367	GAS	288,818 MCF	1.00	288,818	1,144,963	3.71
17 AVON PARK	1-2	69	0	0.0	48.17	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
18 BARTOW	1-4	228	0	0.0	85.57	0.0	0	LIGHT OIL	0 BBLS	0.00	0	178	0 00
19 BAYBORO	1-4	231	0	0.0	68.59	0.0	0	LIGHT OIL	0 BBLS	0.00	0	88	0 00
20 DEBARY	1-10	785	0	0.0	81.83	0.0	0	LIGHT OIL	0 BBLS	0.00	0	654	0 00
21 HIGGINS	1-4	129	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
22 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
23 INT CITY	1-14	1,186	0	0.0	94.27	0.0	0	LIGHT OIL	0 BBLS	0.00	0	4,018	0 00
24 SUWANNEE	1-3	200	0	0.0	88.11	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
25 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	712 BBLS	5.83	4,150	137,118	0.00
26 SOLAR		316	89,105	39.2	0.00	70.8	0	SOLAR	0 N/A		0	0	0 00
27 TOTAL			3,806,577								28,159,969	108,663,879	2 85

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-20

	(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	288,370	53.0	93.73	56 2	10,727	COAL	130,465 TONS	23.71	3,093,287	10,920,975	3.79
2	CRYSTAL RIVER	5	712	125,018	23.6	93 85	57 8	10,621	COAL	56,001 TONS	23.71	1,327,763	5,545,844	4.44
3	ANCLOTE	1	517	92,203	24.0	89 35	26 8	11,307	GAS	1,042,572 MCF	1.00	1,042,572	3,372,695	3.66
4	ANCLOTE	2	521	1,388	0.4	98 06	24 2	13,344	GAS	18,520 MCF	1.00	18,520	747,028	53.82
5	AVON PARK	1-2	69	0	0.0	49 03	0 0	0	GAS	0 MCF	0.00	0	0	0.00
6	BARTOW	1-4	228	35	0.0	84 58	15 3	14,253	GAS	496 MCF	1.00	496	2,247	6.46
7	BARTOW CC	1	1279	693,364	72.9	97.42	74 9	7,708	GAS	5,344,271 MCF	1.00	5,344,271	20,047,313	2.89
8	CITRUS CC	1-2	1640	1,152,174	94.4	96 94	98.1	6,524	GAS	7,516,878 MCF	1.00	7,516,878	29,035,977	2.52
9	DEBARY	1-10	785	11,239	1.9	82 95	9 3	13,032	GAS	146,472 MCF	1.00	146,472	559,304	4.98
10	HIGGINS	1-4	129	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
11	HINES CC	1-4	2,204	1,284,960	78.4	96 94	81.7	7,195	GAS	9,245,511 MCF	1.00	9,245,511	35,710,020	2.78
12	NT CITY	1-14	1,186	11,014	1.2	94 80	6.4	12,915	GAS	142,239 MCF	1.00	142,239	536,575	4.87
13	OSPREY CC	1	505	189,107	50.3	94.14	88.1	7,662	GAS	1,448,929 MCF	1.00	1,448,929	5,648,039	2.99
14	SUWANNEE CT	1-3	200	3,227	2.2	86 64	24 8	13,578	GAS	43,821 MCF	1.00	43,821	170,586	5.29
15	TIGER BAY CC	1	225	125,418	74.9	95.16	88 8	7,436	GAS	932,592 MCF	1.00	932,592	3,584,821	2.86
16	UNIV OF FLA. CC	1	47	31,469	90.0	96.15	93 6	9,370	GAS	294,877 MCF	1.00	294,877	1,169,761	3.72
17	AVON PARK	1-2	69	0	0.0	49 03	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
18	BARTOW	1-4	228	0	0.0	84 58	0 0	0	LIGHT OIL	0 BBLS	0.00	0	178	0.00
19	BAYBORO	1-4	231	0	0.0	69.42	0 0	0	LIGHT OIL	0 BBLS	0.00	0	88	0.00
20	DEBARY	1-10	785	0	0.0	82 95	0 0	0	LIGHT OIL	0 BBLS	0.00	0	654	0.00
21	HIGGINS	1-4	129	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
22	OTHER		0	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23	NT CITY	1-14	1,186	0	0.0	94 80	0 0	0	LIGHT OIL	0 BBLS	0.00	0	4,018	0.00
24	SUWANNEE	1-3	200	0	0.0	86 64	0 0	0	LIGHT OIL	0 BBLS		0	0	0.00
25	OTHER & START UP		-	0	-	0 00	0 0	0	LIGHT OIL	1,353 BBLS	5.83	7,885	188,486	0.00
26	SOLAR		316	87,177	37.1	0 00	67 3	0	SOLAR	0 N/A		0	0	0.00
27	TOTAL			4,096,163								30,606,113	117,244,609	2.86

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-20

	(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	46,507	8.5	92.83	58 8	10,664	COAL	21,014 TONS	23 60	495,939	3,008,542	6.47
2	CRYSTAL RIVER	5	712	296,974	56.1	95.33	58 5	10,617	COAL	133,605 TONS	23 60	3,153,080	11,072,391	3.73
3	ANCLOTE	1	517	73,167	19.0	95.16	30 6	11,110	GAS	812,855 MCF	1 00	812,855	3,496,897	4.78
4	ANCLOTE	2	521	101,122	26.1	98.06	26 6	12,159	GAS	1,229,524 MCF	1 00	1,229,524	4,571,902	4.52
5	AVON PARK	1-2	69	0	0.0	48.07	0 0	0	GAS	0 MCF	0 00	0	0	0.00
6	BARTOW	1-4	228	9	0.0	85.39	0 0	14,444	GAS	130 MCF	1 00	130	824	9.16
7	BARTOW CC	1	1279	685,694	72.1	96.77	74 5	7,706	GAS	5,283,917 MCF	1 00	5,283,917	19,786,432	2.89
8	CITRUS CC	1-2	1640	1,106,343	90.7	93.71	98.1	6,530	GAS	7,224,266 MCF	1 00	7,224,266	27,845,655	2.52
9	DEBARY	1-10	785	7,556	1.3	81.69	10 0	12,815	GAS	96,827 MCF	1 00	96,827	381,855	5.05
10	HIGGINS	1-4	129	0	0.0	0.00	0 0	0	GAS	0 MCF	0 00	0	0	0.00
11	HINES CC	1-4	2,204	1,306,563	79.7	97.74	81 9	7,193	GAS	9,398,295 MCF	1 00	9,398,295	36,229,221	2.77
12	INT CITY	1-14	1,186	6,147	0.7	93.47	6 6	12,828	GAS	78,852 MCF	1 00	78,852	315,732	5.14
13	OSPREY CC	1	505	190,268	50.6	94.07	88 0	7,660	GAS	1,457,399 MCF	1 00	1,457,399	5,650,224	2.97
14	SUWANNEE CT	1-3	200	2,545	1.7	86.33	24 9	13,563	GAS	34,513 MCF	1 00	34,513	138,000	5.42
15	TIGER BAY CC	1	225	120,730	72.1	95.16	88 8	7,454	GAS	899,943 MCF	1 00	899,943	3,492,297	2.89
16	UNIV OF FLA. CC	1	47	31,786	90.9	97.09	93.7	9,366	GAS	297,712 MCF	1 00	297,712	1,178,219	3.71
17	AVON PARK	1-2	69	0	0.0	48.07	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
18	BARTOW	1-4	228	0	0.0	85.39	0 0	0	LIGHT OIL	0 BBLS	0 00	0	178	0.00
19	BAYBORO	1-4	231	0	0.0	69.13	0 0	0	LIGHT OIL	0 BBLS	0 00	0	88	0.00
20	DEBARY	1-10	785	4	1.3	81.69	0 0	19,500	LIGHT OIL	13 BBLS	6 00	78	1,723	43.08
21	HIGGINS	1-4	129	0	0.0	0.00	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
22	OTHER		0	0	0.0	0.00	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
23	INT CITY	1-14	1,186	3	0.7	93.47	0 0	16,000	LIGHT OIL	8 BBLS	6 00	48	4,671	155.70
24	SUWANNEE	1-3	200	3	1.7	86.33	0 0	16,667	LIGHT OIL	9 BBLS	5 56	50	699	23.30
25	OTHER & START UP		-	0	-	0.00	0 0	0	LIGHT OIL	499 BBLS	5 82	2,905	120,824	0.00
26	SOLAR		316	84,489	35.9	0.00	66 3	0	SOLAR	0 N/A		0	0	0.00
27	TOTAL			4,059,908								30,466,333	117,296,374	2.89

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-20

	(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	13,810	2 6	94.64	65.1	10,535	COAL	6,181 TONS	23.54	145,493	1,943,872	14 08
2	CRYSTAL RIVER	5	712	275,689	53 8	94.63	56.6	10,659	COAL	124,833 TONS	23.54	2,938,488	10,398,055	3.77
3	ANCLOTE	1	517	43,042	11 6	94.00	32.4	11,057	GAS	475,904 MCF	1.00	475,904	2,470,297	5.74
4	ANCLOTE	2	521	94,769	25 3	98.00	25.8	12,199	GAS	1,156,111 MCF	1.00	1,156,111	4,209,586	4.44
5	AVON PARK	1-2	69	0	0 0	49.00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
6	BARTOW	1-4	228	120	0.1	86.69	26.4	14,037	GAS	1,690 MCF	1.00	1,690	5,767	4.79
7	BARTOW CC	1	1279	626,633	68 0	93.33	72.9	7,710	GAS	4,831,290 MCF	1.00	4,831,290	18,143,774	2 90
8	CITRUS CC	1-2	1640	1,101,690	93 3	96.17	97.6	6,527	GAS	7,190,395 MCF	1.00	7,190,395	27,797,411	2 52
9	DEBARY	1-10	785	8,004	1.4	82.85	10.0	12,815	GAS	102,566 MCF	1.00	102,566	377,266	4.71
10	HIGGINS	1-4	129	0	0 0	0.00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
11	HINES CC	1-4	2,204	1,238,352	78 0	97.25	80.9	7,203	GAS	8,920,211 MCF	1.00	8,920,211	34,511,410	2.79
12	NT CITY	1-14	1,186	7,469	0 9	94.43	6.6	12,816	GAS	95,725 MCF	1.00	95,725	348,826	4 67
13	OSPREY CC	1	505	176,312	48 5	96.65	90.0	7,667	GAS	1,351,773 MCF	1.00	1,351,773	5,240,456	2 97
14	SUWANNEE CT	1-3	200	2,413	1.7	86.83	24.6	13,573	GAS	32,754 MCF	1.00	32,754	123,004	5.10
15	TIGER BAY CC	1	225	97,552	60 2	93.33	88.8	7,481	GAS	729,814 MCF	1.00	729,814	2,805,887	2 88
16	UNIV OF FLA. CC	1	47	30,624	90 5	96.69	93.6	9,370	GAS	286,939 MCF	1.00	286,939	1,138,202	3.72
17	AVON PARK	1-2	69	0	0 0	49.00	0.0	0	LIGHT O L	0 BBLS	0.00	0	0	0 00
18	BARTOW	1-4	228	0	0 0	86.69	0.0	0	LIGHT O L	0 BBLS	0.00	0	178	0 00
19	BAYBORO	1-4	231	0	0 0	68.93	0.0	0	LIGHT O L	0 BBLS	0.00	0	88	0 00
20	DEBARY	1-10	785	0	0 0	82.85	0.0	0	LIGHT O L	0 BBLS	0.00	0	654	0 00
21	HIGGINS	1-4	129	0	0 0	0.00	0.0	0	LIGHT O L	0 BBLS	0.00	0	0	0 00
22	OTHER		0	0	0 0	0.00	0.0	0	LIGHT O L	0 BBLS	0.00	0	0	0 00
23	NT CITY	1-14	1,186	14	0 9	94.43	0.0	14,214	LIGHT O L	34 BBLS	5.85	199	6,728	48 06
24	SUWANNEE	1-3	200	5	1.7	86.83	0.0	13,200	LIGHT O L	11 BBLS	6.00	66	921	18.42
25	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT O L	712 BBLS	5.83	4,150	138,180	0 00
26	SOLAR		316	76,710	33.7	0.00	63.7	0	SOLAR	0 N/A		0	0	0 00
27	TOTAL			3,793,208								28,263,568	109,660,562	2 89

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-20

(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	224,873	41 3	90.46	52.1	10,823	COAL	103,820 TONS	23.44	2,433,893	8,854,251	3.94
2 CRYSTAL RIVER	5	712	164,828	31.1	94.23	56.5	10,645	COAL	74,845 TONS	23.44	1,754,610	6,802,699	4.13
3 ANCLOTE	1	517	12,107	3.1	97.10	30.0	11,228	GAS	135,937 MCF	1 00	135,937	984,600	8.13
4 ANCLOTE	2	521	50,637	13.1	98.06	24.3	12,339	GAS	624,795 MCF	1 00	624,795	2,240,965	4.43
5 AVON PARK	1-2	69	0	0.0	48.39	0 0	0	GAS	0 MCF	0 00	0	0	0.00
6 BARTOW	1-4	228	0	0.0	87.04	0 0	0	GAS	0 MCF	0 00	0	0	0.00
7 BARTOW CC	1	1279	677,553	71 2	96.77	73.6	7,703	GAS	5,219,520 MCF	1 00	5,219,520	20,413,167	3.01
8 CITRUS CC	1-2	1640	716,754	58.7	60.18	97.6	6,533	GAS	4,682,444 MCF	1 00	4,682,444	19,086,342	2.66
9 DEBARY	1-10	785	3,440	0.6	82.29	8.4	13,435	GAS	46,210 MCF	1 00	46,210	192,728	5.60
10 HIGGINS	1-4	129	0	0.0	0.00	0 0	0	GAS	0 MCF	0 00	0	0	0.00
11 HINES CC	1-4	2,204	1,086,446	66 3	84.83	83.0	7,207	GAS	7,829,476 MCF	1 00	7,829,476	32,042,641	2.95
12 INT CITY	1-14	1,186	2,323	0.3	80.41	5.4	13,376	GAS	31,072 MCF	1 00	31,072	131,370	5.66
13 OSPREY CC	1	505	192,159	51.1	96.03	77.3	7,612	GAS	1,462,643 MCF	1 00	1,462,643	6,097,519	3.17
14 SUWANNEE CT	1-3	200	916	0.6	92.70	22.9	14,090	GAS	12,905 MCF	1 00	12,905	53,305	5.82
15 TIGER BAY CC	1	225	109,549	65.4	94.52	88 5	7,465	GAS	817,803 MCF	1 00	817,803	3,341,598	3.05
16 UNIV OF FLA. CC	1	47	2,112	6.0	99.18	93 6	9,358	GAS	19,764 MCF	1 00	19,764	82,623	3.91
17 AVON PARK	1-2	69	0	0.0	48.39	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
18 BARTOW	1-4	228	0	0.0	87.04	0 0	0	LIGHT OIL	0 BBLS	0 00	0	178	0.00
19 BAYBORO	1-4	231	0	0.0	69.85	0 0	0	LIGHT OIL	0 BBLS	0 00	0	88	0.00
20 DEBARY	1-10	785	0	0.0	82.29	0 0	0	LIGHT OIL	0 BBLS	0 00	0	654	0.00
21 HIGGINS	1-4	129	0	0.0	0.00	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
22 OTHER		0	0	0.0	0.00	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
23 INT CITY	1-14	1,186	3	0.3	80.41	0 0	16,000	LIGHT OIL	8 BBLS	6 00	48	4,675	155.83
24 SUWANNEE	1-3	200	0	0.0	92.70	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
25 OTHER & START UP		-	0	-	0.00	0 0	0	LIGHT OIL	1,781 BBLS	5 83	10,375	223,935	0.00
26 SOLAR		316	75,236	32 0	0.00	67.6	0	SOLAR	0 N/A		0	0	0.00
27 TOTAL			3,318,935								25,081,495	100,553,338	3.03

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-20

	(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	24,675	4.7	88.32	56.2	10,430	COAL	10,982 TONS	23.44	257,371	2,279,095	9.24
2	CRYSTAL RIVER	5	712	200,372	39.1	92.76	53.3	10,711	COAL	91,579 TONS	23.44	2,146,258	7,971,496	3.98
3	ANCLOTE	1	517	18,145	4 9	96.67	23.1	11,556	GAS	209,693 MCF	1.00	209,693	797,655	4.40
4	ANCLOTE	2	521	0	0 0	98.00	0.0	0	GAS	0 MCF	0.00	0	246,163	0.00
5	AVON PARK	1-2	69	0	0 0	49.17	0.0	0	GAS	0 MCF	0.00	0	0	0.00
6	BARTOW	1-4	228	6	0 0	85.91	0.0	24,000	GAS	144 MCF	1.00	144	616	10.27
7	BARTOW CC	1	1279	606,989	65 9	95.33	69.2	7,666	GAS	4,653,024 MCF	1.00	4,653,024	19,396,487	3.20
8	CITRUS CC	1-2	1640	682,743	57 8	58.52	96.8	6,505	GAS	4,441,385 MCF	1.00	4,441,385	19,323,281	2.83
9	DEBARY	1-10	785	2,683	0 5	83.04	7.0	13,884	GAS	37,246 MCF	1.00	37,246	164,618	6.14
10	HIGGINS	1-4	129	0	0 0	0.00	0.0	0	GAS	0 MCF	0.00	0	0	0.00
11	HINES CC	1-4	2,204	926,603	58.4	72.50	82.8	7,132	GAS	6,608,868 MCF	1.00	6,608,868	28,821,031	3.11
12	INT CITY	1-14	1,186	1,905	0 2	91.14	5.5	13,192	GAS	25,132 MCF	1.00	25,132	113,743	5.97
13	OSPREY CC	1	505	145,663	40.1	96.21	68.4	7,558	GAS	1,100,980 MCF	1.00	1,100,980	5,180,601	3.56
14	SUWANNEE CT	1-3	200	814	0 6	89.93	19.4	14,532	GAS	11,822 MCF	1.00	11,822	50,602	6.22
15	TIGER BAY CC	1	225	46,821	28 9	95.33	87.4	7,634	GAS	357,424 MCF	1.00	357,424	1,622,495	3.47
16	UNIV OF FLA. CC	1	47	6,970	20 6	94.41	93.9	9,423	GAS	65,677 MCF	1.00	65,677	292,864	4.20
17	AVON PARK	1-2	69	0	0 0	49.17	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
18	BARTOW	1-4	228	0	0 0	85.91	0.0	0	LIGHT OIL	0 BBLS	0.00	0	178	0.00
19	BAYBORO	1-4	231	0	0 0	69.48	0.0	0	LIGHT OIL	0 BBLS	0.00	0	88	0.00
20	DEBARY	1-10	785	4	0 5	83.04	0.0	20,000	LIGHT O L	14 BBLS	5.71	80	1,750	43.75
21	HIGGINS	1-4	129	0	0 0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
22	OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23	INT CITY	1-14	1,186	3	0 2	91.14	0.0	16,667	LIGHT OIL	9 BBLS	5.56	50	4,699	156.63
24	SUWANNEE	1-3	200	0	0 0	89.93	0.0	0	LIGHT O L	0 BBLS	0.00	0	0	0.00
25	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	427 BBLS	5.83	2,490	115,163	0.00
26	SOLAR		316	61,202	26 9	0.00	59.2	0	SOLAR	0 N/A		0	0	0.00
27	TOTAL			2,725,597								19,917,644	86,382,625	3.17

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-20

(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	0	0.0	95.75	0 0	0	COAL	0 TONS	0.00	0	1,503,474	0.00
2 CRYSTAL RIVER	5	712	0	0.0	96.67	0 0	0	COAL	0 TONS	0.00	0	1,503,474	0.00
3 ANCLOTE	1	517	0	0.0	93.55	0 0	0	GAS	0 MCF	0.00	0	663	0.00
4 ANCLOTE	2	521	0	0.0	99.03	0 0	0	GAS	0 MCF	0.00	0	663	0.00
5 AVON PARK	1-2	69	0	0.0	47.74	0 0	0	GAS	0 MCF	0.00	0	0	0.00
6 BARTOW	1-4	228	0	0.0	86.49	0 0	0	GAS	0 MCF	0.00	0	694	0.00
7 BARTOW CC	1	1279	553,199	58.1	92.90	62 5	7,693	GAS	4,255,552 MCF	1.00	4,255,552	17,697,905	3.20
8 CITRUS CC	1-2	1640	1,222,285	100.2	98.23	102 3	6,488	GAS	7,930,271 MCF	1.00	7,930,271	34,121,782	2.79
9 DEBARY	1-10	785	1,999	0.3	82.77	7.1	14,351	GAS	28,681 MCF	1.00	28,681	155,623	7.79
10 HIGG NS	1-4	129	0	0.0	0.00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
11 H NES CC	1-4	2,204	1,062,208	64.8	94.17	86.1	7,026	GAS	7,462,664 MCF	1.00	7,462,664	32,248,215	3.04
12 INT CITY	1-14	1,186	848	0.1	94.68	5 5	13,287	GAS	11,273 MCF	1.00	11,273	49,968	5.89
13 OSPREY CC	1	505	43,408	11.6	95.86	79 6	7,782	GAS	337,800 MCF	1.00	337,800	1,725,159	3.97
14 SUWANNEE CT	1-3	200	4,005	2.7	89.60	22 0	14,333	GAS	57,401 MCF	1.00	57,401	282,351	7.05
15 TIGER BAY CC	1	225	36,406	21.7	95.16	99 9	7,451	GAS	271,261 MCF	1.00	271,261	1,091,056	3.00
16 UNIV OF FLA. CC	1	47	32,899	94.1	96.13	97 9	9,362	GAS	308,008 MCF	1.00	308,008	1,356,930	4.12
17 AVON PARK	1-2	69	0	0.0	47.74	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
18 BARTOW	1-4	228	0	0.0	86.49	0 0	0	LIGHT OIL	0 BBLS	0.00	0	178	0.00
19 BAYBORO	1-4	231	3	0.0	67.95	0 0	19,667	LIGHT OIL	10 BBLS	5.90	59	884	29.47
20 DEBARY	1-10	785	0	0.0	82.77	0 0	0	LIGHT OIL	0 BBLS	0.00	0	654	0.00
21 HIGG NS	1-4	129	0	0.0	0.00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
22 OTHER		0	0	0.0	0.00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23 INT CITY	1-14	1,186	3	0.1	94.68	0 0	18,667	LIGHT OIL	10 BBLS	5.60	56	4,778	159.27
24 SUWANNEE	1-3	200	0	0.0	89.60	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
25 OTHER & START UP		-	0	-	0.00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	81,060	0.00
26 SOLAR		316	53,315	22.7	0.00	50.1	0	SOLAR	0 N/A		0	0	0.00
27 TOTAL			3,010,578								20,663,026	91,825,511	3.05

Duke Energy Florida, LLC
Inventory Analysis
Estimated for the Period of : January 2020 through December 2020

			Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Subtotal
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	78	269	698	551	1,211	712	3,519
3	UNIT COST	$/BBL	1181.00	403.72	208.81	244.70	158.80	199.52	231.79
4	AMOUNT	$	92,118	108,601	145,750	134,827	192,303	142,056	815,655
5	BURNED:								
6	UNITS	BBL	78	269	698	551	1,211	712	3,519
7	UNIT COST	$/BBL	1181.00	403.72	208.81	244.70	158.80	199.52	231.79
8	AMOUNT	$	92,118	108,601	145,750	134,827	192,303	142,056	815,655
9	ENDING INVENTORY:								
10	UNITS	BBL	659,427	659,427	659,427	659,427	659,427	659,427	
11	UNIT COST	$/BBL	108.99	108.99	108.99	108.99	108.99	108.99	
12	AMOUNT	$	71,867,960	71,867,960	71,867,960	71,867,960	71,867,960	71,867,960	
	COAL								
13	PURCHASES:								
14	UNITS	TON	34,402	3,452	41,015	16,485	104,488	139,134	338,976
15	UNIT COST	$/TON	161.40	958.05	146.97	254.79	101.12	93.90	126.02
16	AMOUNT	$	5,552,605	3,307,188	6,028,153	4,200,293	10,565,344	13,063,992	42,717,575
17	BURNED:								
18	UNITS	TON	34,402	3,452	41,015	16,485	104,488	139,134	338,976
19	UNIT COST	$/TON	161.40	958.05	146.97	254.79	101.12	93.90	126.02
20	AMOUNT	$	5,552,605	3,307,188	6,028,153	4,200,293	10,565,344	13,063,992	42,717,575
21	ENDING INVENTORY:								
22	UNITS	TON	417,395	417,395	417,395	417,395	417,395	417,395	
23	UNIT COST	$/TON	86.34	86.34	86.34	86.34	86.34	86.34	
24	AMOUNT	$	36,037,880	36,037,880	36,037,880	36,037,880	36,037,880	36,037,880	
	GAS								
25	BURNED:								
26	UNITS	MCF	20,877,664	19,239,554	18,750,664	19,762,609	23,442,457	24,860,339	126,933,287
27	UNIT COST	$/MCF	4.29	4.31	4.34	4.02	3.93	3.84	4.11
28	AMOUNT	$	89,563,329	82,979,429	81,397,859	79,476,459	92,224,658	95,457,831	521,099,565

Duke Energy Florida, LLC
Inventory Analysis
Estimated for the Period of : January 2020 through December 2020

			Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	1,353	529	757	1,789	450	20	8,417
3	UNIT COST	$/BBL	142.96	242.31	193.86	128.30	270.84	4377.70	204.70
4	AMOUNT	$	193,424	128,183	146,749	229,530	121,878	87,554	1,722,973
5	BURNED:								
6	UNITS	BBL	1,353	529	757	1,789	450	20	8,417
7	UNIT COST	$/BBL	142.96	242.31	193.86	128.30	270.84	4377.70	204.70
8	AMOUNT	$	193,424	128,183	146,749	229,530	121,878	87,554	1,722,973
9	ENDING INVENTORY:								
10	UNITS	BBL	659,427	659,427	659,427	659,427	659,427	659,427	
11	UNIT COST	$/BBL	108.99	108.99	108.99	108.99	108.99	108.99	
12	AMOUNT	$	71,867,960	71,867,960	71,867,960	71,867,960	71,867,960	71,867,960	
	COAL								
13	PURCHASES:								
14	UNITS	TON	186,466	154,619	131,014	178,665	102,561	0	1,092,301
15	UNIT COST	$/TON	88.31	91.07	94.20	87.63	99.95	0.00	104.84
16	AMOUNT	$	16,466,819	14,080,933	12,341,927	15,656,950	10,250,591	3,006,948	114,521,743
17	BURNED:								
18	UNITS	TON	186,466	154,619	131,014	178,665	102,561	0	1,092,301
19	UNIT COST	$/TON	88.31	91.07	94.20	87.63	99.95	0.00	104.84
20	AMOUNT	$	16,466,819	14,080,933	12,341,927	15,656,950	10,250,591	3,006,948	114,521,743
21	ENDING INVENTORY:								
22	UNITS	TON	417,395	417,395	417,395	417,395	417,395	417,395	
23	UNIT COST	$/TON	86.34	86.34	86.34	86.34	86.34	86.34	
24	AMOUNT	$	36,037,880	36,037,880	36,037,880	36,037,880	36,037,880	36,037,880	
	GAS								
25	BURNED:								
26	UNITS	MCF	26,177,178	26,814,233	25,175,172	20,882,569	17,511,395	20,662,911	264,156,745
27	UNIT COST	$/MCF	3.84	3.84	3.86	4.05	4.34	4.29	4.06
28	AMOUNT	$	100,584,366	103,087,258	97,171,886	84,666,858	76,010,156	88,731,009	1,071,351,098

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	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)	GAIN ON POWER SALES $
Jan-20	ECONSALE	--	26,172		26,172	3.700	4.679	968,364	1,224,654	256,290
	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	--	178,942		178,942	2.629	2.629	4,705,071	4,705,071	0
	TOTAL		205,114		205,114	2.766	2.891	5,673,435	5,929,725	256,290
Feb-20	ECONSALE	--	13,104		13,104	2.930	3.705	383,926	485,536	101,610
	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	--	140,498		140,498	2.666	2.666	3,745,252	3,745,252	0
	TOTAL		153,602		153,602	2.688	2.754	4,129,178	4,230,788	101,610
Mar-20	ECONSALE	--	6,029		6,029	2.504	3.167	150,964	190,918	39,954
	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	--	100,365		100,365	2.136	2.136	2,144,160	2,144,160	0
	TOTAL		106,394		106,394	2.157	2.195	2,295,124	2,335,078	39,954
Apr-20	ECONSALE	--	5,703		5,703	2.942	3.721	167,780	212,186	44,406
	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	--	119,025		119,025	2.597	2.597	3,091,043	3,091,043	0
	TOTAL		124,728		124,728	2.613	2.648	3,258,823	3,303,229	44,406
May-20	ECONSALE	--	12,939		12,939	3.375	4.269	436,720	552,304	115,584
	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	--	136,095		136,095	2.107	2.107	2,868,019	2,868,019	0
	TOTAL		149,033		149,033	2.217	2.295	3,304,739	3,420,323	115,584
Jun-20	ECONSALE	--	11,893		11,893	3.662	4.631	435,481	550,736	115,255
	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	--	145,446		145,446	2.226	2.226	3,236,996	3,236,996	0
	TOTAL		157,338		157,338	2.334	2.407	3,672,477	3,787,732	115,255
Jan	ECONSALE	--	75,838		75,838	3.353	4.241	2,543,235	3,216,334	673,099
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Jun-20	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	820,371		820,371	2412.390	2412.390	19,790,541	19,790,541	0
	TOTAL		896,209		896,209	2.492	2.567	22,333,776	23,006,875	673,099

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	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)	GAIN ON POWER SALES $
Jul-20	ECONSALE	--	18,172		18,172	3.461	4.377	628,970	795,435	166,465
	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	--	157,273		157,273	2.256	2.256	3,548,561	3,548,561	0
	TOTAL		175,445		175,445	2.381	2.476	4,177,531	4,343,996	166,465
Aug-20	ECONSALE	--	19,017		19,017	4.219	5.335	802,288	1,014,624	212,336
	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	--	140,015		140,015	2.258	2.258	3,160,893	3,160,893	0
	TOTAL		159,032		159,032	2.492	2.626	3,963,181	4,175,517	212,336
Sep-20	ECONSALE	--	9,754		9,754	3.463	4.379	337,749	427,139	89,390
	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	--	119,663		119,663	2.155	2.155	2,579,263	2,579,263	0
	TOTAL		129,418		129,418	2.254	2.323	2,917,012	3,006,402	89,390
Oct-20	ECONSALE	--	8,389		8,389	3.142	3.974	263,633	333,407	69,774
	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	--	99,225		99,225	2.097	2.097	2,080,583	2,080,583	0
	TOTAL		107,614		107,614	2.178	2.243	2,344,216	2,413,990	69,774
Nov-20	ECONSALE	--	4,778		4,778	3.552	4.492	169,717	214,635	44,918
	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	--	52,495		52,495	2.052	2.052	1,077,352	1,077,352	0
	TOTAL		57,273		57,273	2.177	2.256	1,247,069	1,291,987	44,918
Dec-20	ECONSALE	--	15,974		15,974	2.727	3.449	435,671	550,976	115,305
	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	--	75,379		75,379	2.161	2.161	1,628,658	1,628,658	0
	TOTAL		91,352		91,352	2.260	2.386	2,064,329	2,179,634	115,305
Jan-20	ECONSALE	--	151,923		151,923	3.410	4.313	5,181,263	6,552,550	1,371,287
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-20	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,464,420		1,464,420	2.313	2.313	33,865,852	33,865,852	0
	TOTAL		1,616,343		1,616,343	2.416	2.501	39,047,115	40,418,402	1,371,287

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR NTERRUPTIBLE	MWH FOR F RM	C/KWH (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jan-20	OTHER	--	0			0	0 000	0.000	0
	SHADY HILLS	--	4,083			4,083	5 263	5.263	214,891
	SOCO Franklin	--	20,666			20,666	2 927	2.927	604,986
	Vandolah (NSG)	--	4,355			4,355	6 534	6.534	284,576
	TOTAL		29,104	0	0	29,104	3.795	3.795	1,104,453
Feb-20	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	3,532			3,532	6 048	6.048	213,619
	SOCO Franklin	--	20,238			20,238	3 013	3.013	609,799
	Vandolah (NSG)	--	3,315			3,315	7 344	7.344	243,469
	TOTAL		27,085	0	0	27,085	3 939	3.939	1,066,887
Mar-20	OTHER	--	0			0	0 000	0.000	0
	SHADY HILLS	--	16,656			16,656	5 042	5.042	839,808
	SOCO Franklin	--	83,999			83,999	2 823	2.823	2,371,026
	Vandolah (NSG)	--	8,671			8,671	5.721	5.721	496,088
	TOTAL		109,326	0	0	109,326	3 391	3.391	3,706,922
Apr-20	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	21,731			21,731	3 843	3.843	835,167
	SOCO Franklin	--	49,500			49,500	2 677	2.677	1,324,884
	Vandolah (NSG)	--	13,496			13,496	4.774	4.774	644,283
	TOTAL		84,727	0	0	84,727	3 310	3.310	2,804,334
May-20	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	17,035			17,035	4 582	4.582	780,489
	SOCO Franklin	--	55,610			55,610	2 694	2.694	1,498,045
	Vandolah (NSG)	--	12,536			12,536	5 526	5.526	692,763
	TOTAL		85,181	0	0	85,181	3.488	3.488	2,971,297
Jun-20	OTHER	--	0			0	0 000	0.000	0
	SHADY HILLS	--	61,124			61,124	3.753	3.753	2,294,019
	SOCO Franklin	--	104,941			104,941	2 690	2.690	2,823,385
	Vandolah (NSG)	--	11,035			11,035	5 058	5.058	558,191
	TOTAL		177,100	0	0	177,100	3 205	3.205	5,675,595
Jan-20	OTHER	--	0			0	0 000	0.000	0
THRU	SHADY HILLS	--	124,161			124,161	4.170	4.170	5,177,993
Jun-20	SOCO Franklin	--	334,954			334,954	2.756	2.756	9,232,125
	Vandolah (NSG)	--	53,408			53,408	5.466	5.466	2,919,370
	TOTAL		512,523	0	0	512,523	3 381	3.381	17,329,488

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILIT ES	MWH FOR INTERRUPT BLE	MWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-20	OTHER	--	0			0	0.000	0.000	0
	SHADY H LLS	--	66,109			66,109	4.393	4.393	2,903,903
	SOCO Franklin	--	123,244			123,244	2.700	2.700	3,328,174
	Vandolah (NSG)	--	10,948			10,948	5.497	5.497	601,858
	TOTAL		200,301	0	0	200,301	3.412	3.412	6,833,935
Aug-20	OTHER	--	0			0	0.000	0.000	0
	SHADY H LLS	--	31,575			31,575	4.908	4.908	1,549,819
	SOCO Franklin	--	123,060			123,060	2.710	2.710	3,334,617
	Vandolah (NSG)	--	6,839			6,839	6.073	6.073	415,354
	TOTAL		161,474	0	0	161,474	3.282	3.282	5,299,790
Sep-20	OTHER	--	0			0	0.000	0.000	0
	SHADY H LLS	--	50,262			50,262	4.045	4.045	2,033,127
	SOCO Franklin	--	98,251			98,251	2.718	2.718	2,670,883
	Vandolah (NSG)	--	11,212			11,212	4.997	4.997	560,288
	TOTAL		159,726	0	0	159,726	3.296	3.296	5,264,298
Oct-20	OTHER	--	0			0	0.000	0.000	0
	SHADY H LLS	--	19,389			19,389	5.441	5.441	1,054,986
	SOCO Franklin	--	63,053			63,053	2.696	2.696	1,700,120
	Vandolah (NSG)	--	1,547			1,547	8.520	8.520	131,791
	TOTAL		83,989	0	0	83,989	3.437	3.437	2,886,897
Nov-20	OTHER	--	0			0	0.000	0.000	0
	SHADY H LLS	--	6,989			6,989	4.858	4.858	339,496
	SOCO Franklin	--	23,703			23,703	2.852	2.852	675,953
	Vandolah (NSG)	--	3,851			3,851	6.941	6.941	267,296
	TOTAL		34,543	0	0	34,543	3.713	3.713	1,282,745
Dec-20	OTHER	--	0			0	0.000	0.000	0
	SHADY H LLS	--	9,402			9,402	5.302	5.302	498,500
	SOCO Franklin	--	16,729			16,729	2.921	2.921	488,624
	Vandolah (NSG)	--	5,537			5,537	6.124	6.124	339,046
	TOTAL		31,668	0	0	31,668	4.188	4.188	1,326,170
Jan-20	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY H LLS	--	307,887			307,887	4.404	4.404	13,557,824
Dec-20	SOCO Franklin	--	782,994			782,994	2.737	2.737	21,430,496
	Vandolah (NSG)	--	93,342			93,342	5.608	5.608	5,235,003
TOTAL			1,184,223	0	0	1,184,223	3.397	3.397	40,223,323

Duke Energy Florida, LLC
Energy Payments to Qualifying Facilities
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILIT ES	MWH FOR INTERRUPTIBLE	MWH FOR F RM	C/KWH (A) ENERGY COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-20	QUAL. FAC LITIES	COGEN	254,820			254,820	4.050	14.708	10,321,439
Feb-20	QUAL. FAC LITIES	COGEN	238,380			238,380	4.032	15.425	9,611,794
Mar-20	QUAL. FAC LITIES	COGEN	223,797			223,797	4.229	16.364	9,464,477
Apr-20	QUAL. FAC LITIES	COGEN	232,995			232,995	4.130	15.786	9,623,406
May-20	QUAL. FAC LITIES	COGEN	247,271			247,271	4.086	15.069	10,104,514
Jun-20	QUAL. FAC LITIES	COGEN	239,294			239,294	4.100	15.449	9,810,413
Jul-20	QUAL. FAC LITIES	COGEN	247,271			247,271	4.138	15.121	10,233,157
Aug-20	QUAL. FAC LITIES	COGEN	247,271			247,271	4.146	15.129	10,251,146
Sep-20	QUAL. FAC LITIES	COGEN	233,587			233,587	4.116	15.742	9,613,299
Oct-20	QUAL. FAC LITIES	COGEN	210,877			210,877	4.014	16.893	8,465,057
Nov-20	QUAL. FAC LITIES	COGEN	237,861			237,861	4.153	15.570	9,877,229
Dec-20	QUAL. FAC LITIES	COGEN	264,967			264,967	3.988	14.237	10,565,880
TOTAL	QUAL. FAC LITIES	COGEN	2,878,391			2,878,391	4.097	15.419	117,941,811

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-20	ECONPURCH	--	5,890	3.943	3.943	232,265	4.555	268,303	36,038
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		5,890	3.943	3.943	232,265	4.555	268,303	36,038
Feb-20	ECONPURCH	--	6,761	3.718	3.718	251,357	4.294	290,358	39,001
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		6,761	3.718	3.718	251,357	4.294	290,358	39,001
Mar-20	ECONPURCH	--	9,309	3.554	3.554	330,864	4.106	382,205	51,341
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		9,309	3.554	3.554	330,864	4.106	382,205	51,341
Apr-20	ECONPURCH	--	9,151	3.596	3.596	329,067	4.154	380,129	51,062
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		9,151	3.596	3.596	329,067	4.154	380,129	51,062
May-20	ECONPURCH	--	4,750	4.240	4.240	201,399	4.898	232,653	31,254
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,750	4.240	4.240	201,399	4.898	232,653	31,254
Jun-20	ECONPURCH	--	3,500	4.702	4.702	164,565	5.432	190,104	25,539
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		3,500	4.702	4.702	164,565	5.432	190,104	25,539
Jan-20 THRU Jun-20	ECONPURCH	--	39,361	3.835	3.835	1,509,517	4.430	1,743,752	234,235
	SEPA	--	0	0.000	0.000	0	-	0	-
	TOTAL		39,361	3.835	3.835	1,509,517	4.430	1,743,752	234,235

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-20	ECONPURCH	--	4,164	4.435	4.435	184,692	5.123	213,349	28,657
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,164	4.435	4.435	184,692	5.123	213,349	28,657
Aug-20	ECONPURCH	--	3,303	4.758	4.758	157,157	5.496	181,547	24,390
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		3,303	4.758	4.758	157,157	5.496	181,547	24,390
Sep-20	ECONPURCH	--	4,176	4.700	4.700	196,292	5.430	226,749	30,457
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,176	4.700	4.700	196,292	5.430	226,749	30,457
Oct-20	ECONPURCH	--	4,682	3.944	3.944	184,665	4.556	213,322	28,657
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,682	3.944	3.944	184,665	4.556	213,322	28,657
Nov-20	ECONPURCH	--	7,685	3.598	3.598	276,466	4.156	319,358	42,892
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		7,685	3.598	3.598	276,466	4.156	319,358	42,892
Dec-20	ECONPURCH	--	8,448	3.525	3.525	297,798	4.072	344,004	46,206
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		8,448	3.525	3.525	297,798	4.072	344,004	46,206
Jan-20 THRU Dec-20	ECONPURCH	--	71,819	3.908	3.908	2,806,587	4.514	3,242,081	435,494
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		71,819	3.908	3.908	2,806,587	4.514	3,242,081	435,494

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

	Current Sep-Dec - 2019 ($/1000 kWh)	Requested Jan-2020 [1] ($/1000 kWh)	Difference from Current $	Difference from Current %
Base Rate	$69.11	$71.55	$2.44	3.53%
Fuel Cost Recovery	36.98	30.67	(6.31)	-17.06%
Capacity Cost Recovery (CCR)	11.21	12.00	0.79	7.05%
Energy Conservation Cost Recovery (ECCR)	2.97	3.39	0.42	14.14%
Environmental Cost Recovery (ECRC)	1.43	0.79	(0.64)	-44.76%
Nuclear CR3 Uprate	1.27	0.00	(1.27)	-100.00%
Asset Securitization Charge (ASC)	2.49	2.49	0.00	0.00%
Subtotal	125.46	120.89	(4.57)	-3.64%
Gross Receipts Tax	3.22	3.10	(0.12)	-3.73%
Total	$128.68	$123.99	($4.69)	-3.64%

[1] The January 2020 Base Rate includes proposed adjustments for the Hamilton Solar Power Plant Project True-Up (SoBRA I), Lake Placid and Trenton Solar Power Plant Projects (SoBRA II) and Multi-Year Base Rate Increase filed in Docket No. 20190072.

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	14,752,013	3.350	$	494,192,421	3.067	$	452,465,709
Over 1,000 kWh	5,818,443	3.350		194,917,852	4.067		236,644,564
Total	20,570,456		$	689,110,273		$	689,110,273
Rate Differential by Tier - Cents per kWh					1.000		

Residential Sales:	
Total	20,570,483
Time of Use	27
Levelized	20,570,456

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

		2017 Actual	2018 Actual	2019 Actual/Estimated	2020 Projection	2018 vs. 2017	2019 vs. 2018	2020 vs. 2019
FUEL COST OF SYSTEM NET GENERATION ($)								
LIGHT O L		13,616,153	22,609,544	6,406,085	1,722,973	66.0%	-71.7%	-73.1%
COAL		313,055,107	276,175,645	148,303,408	114,521,743	-11.8%	-46 3%	-22.8%
GAS		928,886,194	1,023,687,201	1,073,325,970	1,071,351,098	10.2%	4 8%	-0.2%
OTHER		0	0	0	0	0.0%	0 0%	0.0%
TOTAL	$	1,255,557,454	1,322,472,390	1,228,035,464	1,187,595,814	5.3%	-7.1%	-3.3%
SYSTEM NET GENERATION (mWh)								
LIGHT O L		62,216	90,434	18,782	181	45.4%	-79 2%	-99.0%
COAL		8,722,203	8,421,960	3,610,045	2,406,835	-3.4%	-57.1%	-33.3%
GAS		27,307,533	28,686,945	36,234,382	36,652,981	5.1%	26 3%	1.2%
SOLAR		15,705	25,744	226,096	841,101	63.9%	778 2%	272.0%
OTHER		0	0	0	0	0.0%	0 0%	0.0%
TOTAL	mWh	36,107,657	37,225,084	40,089,304	39,901,097	3.1%	7.7%	-0.5%
UNITS OF FUEL BURNED								
LIGHT O L	BBL	136,260	198,094	51,716	8,417	45.4%	-73 9%	-83.7%
COAL	TON	4,023,166	3,745,945	1,666,570	1,092,301	-6.9%	-55 5%	-34.5%
GAS	MCF	213,729,336	222,082,583	266,088,201	264,156,745	3.9%	19 8%	-0.7%
OTHER		0	0	0	0	0.0%	0 0%	0.0%
BTUS BURNED (MMBTU)								
LIGHT O L		828,727	1,141,753	297,830	49,027	37.8%	-73 9%	-83.5%
COAL		90,926,387	86,196,682	38,166,941	25,761,017	-5.2%	-55.7%	-32.5%
GAS		218,296,120	226,705,787	268,575,668	264,156,745	3.9%	18 5%	-1.6%
OTHER		0	0	0	0	0.0%	0 0%	0.0%
TOTAL	MMBTU	310,051,234	314,044,222	307,040,439	289,966,789	1.3%	-2 2%	-5.6%
GENERATION MIX (% mWh)								
LIGHT O L		0.17%	0.24%	0.05%	0.00%	58.1%	-82 3%	0.0%
COAL		24.16%	22.62%	9.01%	6.03%	-6.2%	-60.1%	-33.3%
GAS		75.63%	77.06%	90.38%	91.86%	1.9%	17 3%	1.7%
SOLAR		0.04%	0.07%	0.56%	2.11%	0.0%	724 6%	266.0%
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 O L	$/BBL	99 93	114.14	123 87	204.70	14.2%	8 5%	65.3%
COAL	$/TON	77 81	73.73	88 99	104.84	-5.3%	20.7%	17.8%
GAS	$/MCF	4 35	4 61	4 03	4.06	6.1%	-12 5%	0.5%
OTHER		0 00	0 00	0 00	0.00	0.0%	0 0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)								
LIGHT O L		16.43	19 80	21 51	35.14	20.5%	8 6%	63.4%
COAL		3.44	3 20	3 89	4.45	-6.9%	21 3%	14.4%
GAS		4 26	4 52	4 00	4.06	6.1%	-11 5%	1.5%
OTHER		0 00	0 00	0 00	0.00	0.0%	0 0%	0.0%
TOTAL	$/MMBTU	4 05	4 21	4 00	4.10	4.0%	-5 0%	2.4%
BTU BURNED PER kWh (BTU/kWh)								
LIGHT O L		13,320	12,625	15,857	270,718	-5.2%	25 6%	1607.2%
COAL		10,425	10,235	10,572	10,703	-1.8%	3 3%	1.2%
GAS		7,994	7,903	7,412	7,207	-1.1%	-6 2%	-2.8%
OTHER		0	0	0	0	0.0%	0 0%	0.0%
TOTAL	BTU/kWh	8,587	8,436	7,659	7,267	-1.8%	-9 2%	-5.1%
GENERATED FUEL COST PER kWh (C/kWh)								
LIGHT O L		21 89	25 00	34.11	951.39	14.2%	36.4%	2689.4%
COAL		3 59	3 28	4.11	4.76	-8.6%	25 3%	15.8%
GAS		3.40	3 57	2 96	2.92	4.9%	-17 0%	-1.3%
OTHER		0 00	0 00	0 00	0.00	0.0%	0 0%	0.0%
TOTAL	C/kWh	3.48	3 55	3 06	2.98	2.2%	-13 8%	-2.8%

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 2020 through December 2020

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	PreTax Weighted Cost Rate
Common Equity	$ 4,874,577	41.01%	10.50%	4.31%	5.77%
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%
Deferred Tax (FAS 109)	-	0.00%	0.00%	0.00%	0.00%
ITC	19,806	0.17%	7.71%	0.01%	0.01%
	11,884,905	100.00%		6.27%	7.74%
			Total Debt	1.97%	1.97%
			Total Equity	4.31%	5.77%

Above is the May 2019 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU, Docket 20120007-EI. Pursuant to the unopposed motion filed on August 21, 2019 in Docket Nos. 20190001, 20190002 and 20190007, DEF does not require the alternative calculation of WACC because the Limitation Provision in Treasury Regulation Section 1.167(l)-l(h)(6)(i) is expected to be met.

Docket No. 20190001-EI
Exhibit No. ____(CAM-3)
Part 3

DUKE ENERGY FLORIDA, LLC

Fuel and Capacity Cost Recovery Factor

January through December 2020

PART 3 – 2020 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

Duke Energy Florida, LLC
Calculation of Projected Capacity Costs
For the Year 2020

Docket No. 20190001-EI
Exhibit__CAM-3, Part 3
Schedule E12-A

		EST Jan-20	EST Feb-20	EST Mar-20	EST Apr-20	EST May-20	EST Jun-20	EST Jul-20	EST Aug-20	EST Sep-20	EST Oct-20	EST Nov-20	EST Dec-20	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	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	5,887,169	5,887,169	70,646,029
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	71,080,257
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/ROYSTER)	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	97,040,598
7	Subtotal - Base Level Capacity Costs	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	325,890,424
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	25,225,277	25,225,276	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	302,703,317
10	**Intermediate Production Level Capacity Costs**													
11	Southern Franklin	4,803,596	4,803,596	2,834,972	2,834,972	3,116,204	5,366,060	6,490,988	6,490,988	4,803,596	2,834,972	2,834,972	3,678,668	50,893,581
12	Schedule H Capacity Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Subtotal - Intermediate Level Capacity Costs	4,803,596	4,803,596	2,834,972	2,834,972	3,116,204	5,366,060	6,490,988	6,490,988	4,803,596	2,834,972	2,834,972	3,678,668	50,893,581
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	3,492,358	3,492,358	2,061,110	2,061,110	2,265,575	3,901,286	4,719,143	4,719,143	3,492,358	2,061,110	2,061,110	2,674,502	37,001,161
16	**Peaking Production Level Capacity Costs**													
17	Shady Hills	1,978,175	1,978,175	1,412,982	1,370,803	1,919,125	3,901,517	3,901,517	3,901,517	1,820,708	1,370,803	1,370,803	1,978,175	26,904,299
18	Vandolah (NSG)	2,770,874	2,786,429	1,997,185	1,974,963	2,693,097	5,552,672	5,536,005	5,491,562	2,628,284	1,936,075	1,980,519	2,786,429	38,134,092
19	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal - Peaking Level Capacity Costs	4,749,048	4,764,603	3,410,167	3,345,766	4,612,222	9,454,189	9,437,522	9,393,079	4,448,992	3,306,878	3,351,322	4,764,603	65,038,391
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	4,555,477	4,570,398	3,271,168	3,209,393	4,424,228	9,068,836	9,052,849	9,010,217	4,267,651	3,172,090	3,214,722	4,570,398	62,387,427
23	**Other Capacity Costs**													
24	Retail Wheeling	(49,081)	(26,693)	(6,391)	(8,251)	(22,290)	(26,580)	(30,641)	(32,297)	(17,960)	(15,271)	(8,249)	(27,392)	(271,098)
25	Ridge Generating Station L P. Termination[1]	709,446	705,945	702,444	698,943	695,442	691,941	688,439	684,938	681,437	677,936	674,435	670,934	8,282,280
26	SoBRA True-Up - Hamilton [2]	(478,334)								-				(478,334)
27	Total Other Capacity Costs	182,032	679,252	696,053	690,691	673,152	665,360	657,798	652,641	663,477	662,665	666,186	643,541	7,532,848
28	**Total Capacity Costs (line 9+15+22+27)**	33,455,143	33,967,284	31,253,608	31,186,470	32,588,230	38,860,759	39,655,066	39,607,278	33,648,763	31,121,141	31,167,294	33,113,718	409,624,753
29	Actual/Estimated True-Up Provision - Jan - Dec 2019													(1,848,509)
30	**Total Capacity Costs w/ True-Up**													407,776,244
31	Revenue Tax Multiplier													1.00072
32	**Total Recoverable Capacity Costs**													408,069,843
33	**ISFSI Revenue Requirement**[3]													6,879,837
34	Revenue Tax Multiplier													1.00072
35	**Total Recoverable ISFSI Costs**													6,884,790
36	**Total Recoverable Capacity & ISFSI Costs (line 32+35)**													414,954,634

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] Proposed true-up of Hamilton Solar Project costs per paragraph 15g of the 2017 Settlement filed in Docket No. 20190072.
[3] Approved in Commission Order No. PSC-2016-0425-PAA-EI.

Contract Data:

	Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
1	Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	115.00
2	Orange Cogen (ORANGECO)	Jul-95	Dec-25	QF	Purch	104.00
3	Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
4	Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
5	Polk Power Partners, L. P. (MULBERY/ROYSTER)	Aug-94	Aug-24	QF	Purch	115.00
6	Southern - Franklin	Jun-16	May-21	Other	Purch	424.00
7	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	1.00
8	Vandolah (NSG)	Jun-12	May-27	Other	Purch	655.00
9	Shady Hills Tolling Agreement	Apr-07	Apr-24	Other	Purch	515.00

(1) The New Smyrna Beach (NSB) Schedule H contract is in effect until cancelled by either Duke Energy Florida or NSB upon 1 year's written notice.

Duke Energy Florida, LLC
Calculation of Actual/Estimated Capacity True-up
For the Year 2019

Docket No. 20190001-EI
Exhibit__CAM-3, Part 3
Schedule E12-B
Page 1 of 1

		ACT Jan-19	ACT Feb-19	ACT Mar-19	ACT Apr-19	ACT May-19	ACT Jun-19	EST Jul-19	EST Aug-19	EST Sep-19	EST Oct-19	EST Nov-19	EST Dec-19	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	67,211,204
3	Orlando Cogen Limited (ORLACOGL)	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	67,633,942
4	Pasco County Resource Recovery (PASCOUNT)	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	24,230,040
5	Pinellas County Resource Recovery (PINCOUNT)	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	57,678,030
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	92,326,986
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	0	-	-	-	-	-	-	-	-	-	-	800,946
8	Subtotal - Base Level Capacity Costs	26,557,630	25,756,684	25,756,684	25,756,684	25,756,684	25,756,684	25,756,683	25,756,683	25,756,683	25,756,683	25,756,683	25,756,683	309,881,148
9	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%	
10	Base Level Jurisdictional Capacity Costs	24,668,054	23,924,096	23,924,096	23,924,096	23,924,096	23,924,096	23,924,095	23,924,095	23,924,095	23,924,095	23,924,095	23,924,095	287,833,104
11	**Intermediate Production Level Capacity Costs**													
12	Southern Franklin	4,611,942	4,802,362	2,752,978	2,755,639	2,814,130	5,254,911	6,374,293	6,374,293	4,712,941	2,774,697	2,774,697	3,605,373	49,608,256
13	Schedule H Capacity Sales	(48,411)	-	(64,548)	-	-	(114,031)	-	-	-	-	-	-	(226,990)
14	Subtotal - Intermediate Level Capacity Costs	4,563,531	4,802,362	2,688,430	2,755,639	2,814,130	5,140,880	6,374,293	6,374,293	4,712,941	2,774,697	2,774,697	3,605,373	49,381,266
15	Intermediate Production Jurisdictioinal 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%	
16	Intermediate Level Jurisdictional Capacity Costs	3,317,824	3,491,461	1,954,569	2,003,433	2,045,957	3,737,574	4,634,302	4,634,302	3,426,450	2,017,288	2,017,288	2,621,214	35,901,661
17	**Peaking Production Level Capacity Costs**													
18	Shady Hills	1,976,940	1,976,940	1,412,100	1,366,200	1,912,680	3,888,000	3,901,517	3,901,517	1,820,708	1,370,803	1,370,803	1,978,175	26,876,383
19	Vandolah	2,919,279	2,891,051	1,947,614	1,942,582	2,793,653	5,773,604	5,536,005	5,491,562	2,628,284	1,936,075	1,980,519	2,786,429	38,626,658
20	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Subtotal - Peaking Level Capacity Costs	4,896,219	4,867,991	3,359,714	3,308,782	4,706,333	9,661,604	9,437,522	9,393,079	4,448,992	3,306,878	3,351,322	4,764,603	65,503,041
22	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%	
23	Peaking Level Jurisdictional Capacity Costs	4,696,650	4,669,572	3,222,772	3,173,916	4,514,503	9,267,797	9,052,849	9,010,217	4,267,651	3,172,090	3,214,722	4,570,398	62,833,137
24	**Other Capacity Costs**													
25	Retail Wheeling	(45,534)	(8,443)	(35,373)	(39,200)	(57,327)	(29,146)	(27,612)	(34,680)	(22,418)	(10,341)	(6,562)	(15,612)	(332,248)
26	Ridge Generating Station L P. Termination [1]	-	750,770	747,221	743,672	740,123	736,573	730,453	726,952	723,451	719,950	716,449	712,948	8,048,562
27	Total Other Capacity Costs	(45,534)	742,327	711,848	704,472	682,796	707,428	702,842	692,272	701,033	709,609	709,887	697,335	7,716,315
28	**Total Capacity Costs (Line 10+16+23+27)**	32,636,994	32,827,456	29,813,285	29,805,916	31,167,352	37,636,894	38,314,088	38,260,887	32,319,229	29,823,082	29,865,992	31,813,043	394,284,217
29	**Nuclear Cost Recovery Clause**													
30	CR3 Uprate Costs [2]	3 775 626	3 753 198	3 730 770	3 708 343	3 685 916	3 663 488	3 641 061	3 618 633	3 596 207	3 573 779	3 551 352	3 528 924	43 827 298
31	**Total Nuclear Cost Recovery Clause Costs**	3,775,626	3,753,198	3,730,770	3,708,343	3,685,916	3,663,488	3,641,061	3,618,633	3,596,207	3,573,779	3,551,352	3,528,924	43,827,298
32	**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
33	**Total Recov Capacity & Nuclear Costs (Line 28+31+32)**	36,985,939	37,153,974	34,117,375	34,087,579	35,426,587	41,873,703	42,528,468	42,452,840	36,488,756	33,970,181	33,990,663	35,915,287	444,991,352
34	**Capacity Revenues**													
35	Capacity Cost Recovery Revenues (net of tax)	29,661,483	30,804,405	30,389,686	31,169,336	34,653,964	41,304,162	42,125,264	42,483,642	43,580,645	39,787,264	33,521,424	31,582,385	431,063,659
36	Prior Period True-Up Provision Over/(Under) Recovery	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	16,610,473
37	**Current Period Revenues (net of tax)**	31,045,689	32,188,611	31,773,892	32,553,542	36,038,171	42,688,368	43,509,470	43,867,848	44,964,851	41,171,470	34,905,630	32,966,591	447,674,132
38	**True-Up Provision**													
39	True-Up Provision - Over/(Under) Recov (Line 37-33)	(5,940,250)	(4,965,363)	(2,343,483)	(1,534,037)	611,583	814,665	981,002	1,415,008	8,476,095	7,201,289	914,967	(2,948,696)	2,682,780
40	Interest Provision for the Month	24,206	10,633	535	(6,274)	(9,873)	(10,962)	(6,166)	(6,142)	802	6,504	6,050	1,810	11,121
41	Current Cycle Balance - Over/(Under)	(5,916,044)	(10,870,774)	(13,213,723)	(14,754,034)	(14,152,324)	(13,348,621)	(12,373,785)	(10,964,919)	(2,488,022)	4,719,770	5,640,787	2,693,901	2,693,901
42	Prior Period Balance - Over/(Under) Recovered	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080
43	Prior Period Cumulative True-Up Collected/(Refunded)	(1,384,206)	(2,768,412)	(4,152,618)	(5,536,824)	(6,921,030)	(8,305,235)	(9,689,442)	(11,073,648)	(12,457,854)	(13,842,060)	(15,226,266)	(16,610,472)	(16,610,472)
44	Prior Period True-up Balance - Over/(Under)	14,380,874	12,996,668	11,612,462	10,228,256	8,844,049	7,459,844	6,075,638	4,691,432	3,307,226	1,923,020	538,814	(845,392)	(845,392)
45	**Net Capacity True-up Over/(Under) (Line 41+44)**	$8,464,830	$2,125,894	($1,601,260)	($4,525,777)	($5,308,274)	($5,888,777)	($6,298,147)	($6,273,487)	$819,204	$6,642,790	$6,179,601	$1,848,509	$1,848,509

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] Approved in Commission Order No. PSC-2018-0490-FOF-EI.
[3] Approved in Commission Order No. PSC-2016-0425-PAA-EI.

Duke Energy Florida, LLC
Calculation of Energy and Demand Percent by Rate Class
Using 12 CP & 1/13th AD Allocation Method for Production Demand
For the Year 2020

Docket No. 20190001-EI
Exhibit__CAM-3, Part 3
Schedule E12-D

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) 12CP 1/13 AD Demand Allocator (%)	(11) Base Energy & Demand Revenues ($000s)	(12) ISFSI Uniform Percent Allocation ($000s)
Residential												**0.32%**
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	0 548	20,570,483	4,275 04	0 9356728	21,984,697	4,568.95	2,502 81	52.312%	60.038%	59.444%	1,365,793	4,386
General Service Non-Demand												
GS-1, GST-1												
Secondary	0 576	2,111,508	417 57	0 9356728	2,256,673	446.28	256 91	5.370%	5.864%	5 826%		
Primary	0 576	20,599	4 07	0 9735768	21,158	4.18	2.41	0.050%	0.055%	0 055%		
Transmission	0 576	2,540	0 50	0 9835768	2,582	0.51	0 29	0.006%	0.007%	0 007%		
								5.426%	5.926%	5 887%	141,030	453
General Service												
GS-2 Secondary	1 000	203,276	23.14	0 9356728	217,251	24.73	24.73	0.517%	0.325%	0 340%	5,159	17
General Service Demand												
GSD-1, GSDT-1												
Secondary	0.742	11,560,312	1,772.76	0 9356728	12,355,079	1,894.63	1,406 54	29.399%	24.896%	25 243%		
Transm Del/ Primary Mtr	0.742	0	0 00	0 9735768	0	0.00	0 00	0.000%	0.000%	0 000%		
Sec Del/Primary Mtr	0.742	27,874	4 27	0 9735768	28,631	4.39	3 26	0.068%	0.058%	0 058%		
Primary	0.742	2,210,723	339 01	0 9735768	2,270,723	348.21	258 51	5.403%	4.576%	4 639%		
SS-1 Primary	0.796	32,819	4 69	0 9735768	33,710	4.82	3 84	0.080%	0.063%	0 065%		
Transm Del/ Primary Mtr	0.796	1,889	0 27	0 9735768	1,940	0.28	0 22	0.005%	0.004%	0 004%		
Transmission	0.796	6,147	0 88	0 9835768	6,250	0.89	0.71	0.015%	0.012%	0 012%		
								34.970%	29.608%	30 021%	557,250	1,789
Curtailable												
CS-1, CST-1, CS-2, CST-2, SS-3												
Primary	1 082	70,228	7 39	0 9735768	72,134	7.59	8 21	0.172%	0.100%	0.105%		
SS-3 Primary	1 248	52,769	4 81	0 9735768	54,201	4.94	6.17	0.129%	0.065%	0 070%		
								0.301%	0.165%	0.175%	5,437	17
Interruptible												
IS-1, IST-1, IS-2, IST-2												
Secondary	0 911	311,838	38 96	0 9356728	333,277	41.64	37 94	0.793%	0.547%	0 566%		
Sec Del/Primary Mtr	0 911	5,039	0 63	0 9735768	5,176	0.65	0 59	0.012%	0.008%	0 009%		
Primary Del / Primary Mtr	0 911	1,146,956	143 29	0 9735768	1,178,085	147.18	134.12	2.803%	1.934%	2 001%		
Primary Del / Transm Mtr	0 911	214	0 03	0 9835768	218	0.03	0 02	0.001%	0.000%	0 000%		
Transm Del/ Primary Mtr	0 911	305,362	38.15	0 9735768	313,650	39.18	35.71	0.746%	0.515%	0 533%		
Transm Del/ Transm Mtr	0 911	374,835	46 83	0 9835768	381,094	47.61	43 38	0.907%	0.626%	0 647%		
SS-2 Primary	0 686	62,736	10.41	0 9735768	64,439	10.70	7 34	0.153%	0.141%	0.142%		
Transm Del/ Primary Mtr	0 686	10,244	1.70	0 9735768	10,522	1.75	1 20	0.025%	0.023%	0 023%		
Transmission	0 686	38,936	6.46	0 9835768	39,586	6.57	4 51	0.094%	0.086%	0 087%		
								5.535%	3.880%	4 008%	59,682	192
Lighting												
LS-1 (Secondary)	10.191	369,250	4.12	0 9356728	394,635	4.41	44 93	0.939%	0.058%	0.126%	9,744	31
Total		39,496,576	7,145 00		42,025,709	7,610.12	4,784 35	100.000%	100.000%	100 000%	2,144,095	6,885

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2018 (FPSC rule 25-6 0437 (7))
(2) Projected mWh sales for the period Jan-Dec 2020
(3) Calculated: Column 2 / (8,784 hours x Column 1)
(4) Based on system average line loss analysis for 2018
(5) Calculated: Column 2 / Column 4
(6) Calculated: Column 3 / Column 4
(7) Calculated: Column 5 / 8,784 hours
(8) Calculated: Column 7 / Total Column 7
(9) Calculated: Column 6 / Total Column 6
(10) Calculated: Column 8 x 1/13 + Column 9 x 12/13
(11) Projected Base Energy & Demand Revenues for Jan-Dec 2020
(12) Uniform Percent Calculated: Column 12 Total / Column 11 Total
Calculated: Column 11 x Uniform Percent

Duke Energy Florida, LLC
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2020

Docket No. 20190001-EI
Exhibit__CAM-3, Part 3
Schedule E12-E
Page 1 of 1

Rate Class	(1) 12CP 1/13 AD Demand Allocator (%)	(2) Effective mWh at Secondary Level (MWh)	(3) Capacity Production Demand Costs ($)	(4) ISFSI Dry Cask Storage Costs ($)	(5) Capacity + ISFSI Production Demand Costs ($)	(6) Capacity CCR Factor (c/kWh)	(7) ISFSI CCR Factor (c/kWh)	(8) Capacity + ISFSI CCR Factor (c/kWh)	(9) Billing KW Load Factor (%)	(10) Projected Effective KW at Meter Level (kW)	(11) Capacity CCR Factor ($/kW-mo)	(12) ISFSI CCR Factor ($/kW-mo)	(13) Capacity + ISFSI CCR Factor ($/kW-mo)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	59.444%	20,570,483	$242,571,083	$4,385,625	$246,956,708	**1.179**	**0.021**	**1.200**					
General Service Non-Demand													
GS-1, GST-1													
Secondary		2,111,508				**1.126**	**0.021**	**1.147**					
Primary		20,393				**1.115**	**0.021**	**1.136**					
Transmission		2,489				**1.103**	**0.021**	**1.124**					
TOTAL GS	5 887%	2,134,390	24,025,105	452,855	24,477,960								
General Service													
GS-2 Secondary	0 340%	203,276	1,386,466	16,565	1,403,031	**0.682**	**0.008**	**0.690**					
General Service Demand													
GSD-1, GSDT-1, SS-1													
Secondary		11,560,312									**3.55**	**0.05**	**3.60**
Primary		2,250,572									**3.51**	**0.05**	**3.56**
Transmission		6,024									**3.48**	**0.05**	**3.53**
TOTAL GSD	30 021%	13,816,908	122,505,608	1,789,356	124,294,964				54.70%	34,507,418			
Curtailable													
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3													
Secondary		-									**1.34**	**0.03**	**1.38**
Primary		121,767									**1.33**	**0.03**	**1.37**
Transmission		-									**1.31**	**0.03**	**1.35**
TOTAL CS	0.175%	121,767	714,722	17,459	732,181				31.30%	531,464			
Interruptible													
IS-1, IST-1, IS-2, IST-2, SS-2													
Secondary		311,838									**2.97**	**0.03**	**3.00**
Primary		1,515,034									**2.94**	**0.03**	**2.97**
Transmission		405,705									**2.91**	**0.03**	**2.94**
TOTAL IS	4 008%	2,232,577	16,353,892	191,641	16,545,533				55.30%	5,515,314			
Lighting													
LS-1 Secondary	0.126%	369,250	512,969	31,289	544,258	**0.139**	**0.008**	**0.147**					
Total	100 000%	39,448,650	$408,069,843	$6,884,790	$414,954,634	**1.034**	**0.017**	**1.051**					

Notes:
(1) From Schedule E12-D, Column 10
(2) Projected mWh sales at effective voltage level for Jan-Dec 2020
(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	$141,572,677	40,554,195	3.49

SS-1, 2, 3 - $/kW-mo	Secondary	Primary	Trans
Monthly - $3.49/kW * 10%	0.349	0 346	0.342
Daily - $3.49/kW / 21	0.166	0.164	0.163

Exhibit not moved in the record.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 8
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: Jeffrey Swartz JS-1

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

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

Executive Summary

Over the past 3 plus years, Duke Energy Florida LLC (Duke), at times working independently and at times together with Mitsubishi Hitachi Power Systems (MHPS), undertook a root cause analysis (RCA) of the cause(s) for the Unit 4S L-0 blade cracks and failures that occurred during normal station operations at Bartow Station.

[redacted]



Historical Overview

Bartow is a 4x1 CC Station with a steam turbine (ST) manufactured by MHPS. The ST was purchased from Tenaska Power Equipment, LLC (Tenaska) which intended to use it for a 3x1 CC with a gross output of 420MW. The ST was never delivered to Tenaska and remained with MHPS in a warehouse in Japan until Duke purchased the unit in 2006.



Before the ST was purchased by Duke, Duke contracted with MHPS to evaluate the ST design conditions and to update heat balances for a 4x1 CC configuration. MHPS updated the heat balances for use in a 4x1 CC configuration. CC units blend steam from the combustion turbines (CT) as they start-up and/or shut-down with steam to the ST. These blending events, which are a common occurrence for CC units, result in brief periods of higher steam temperatures and flows into the condenser near the ST L-0 blades.

Since commissioning of the Bartow ST in 2009, there have been five (5) events involving L-0 blade failures and/or replacements as described, below.

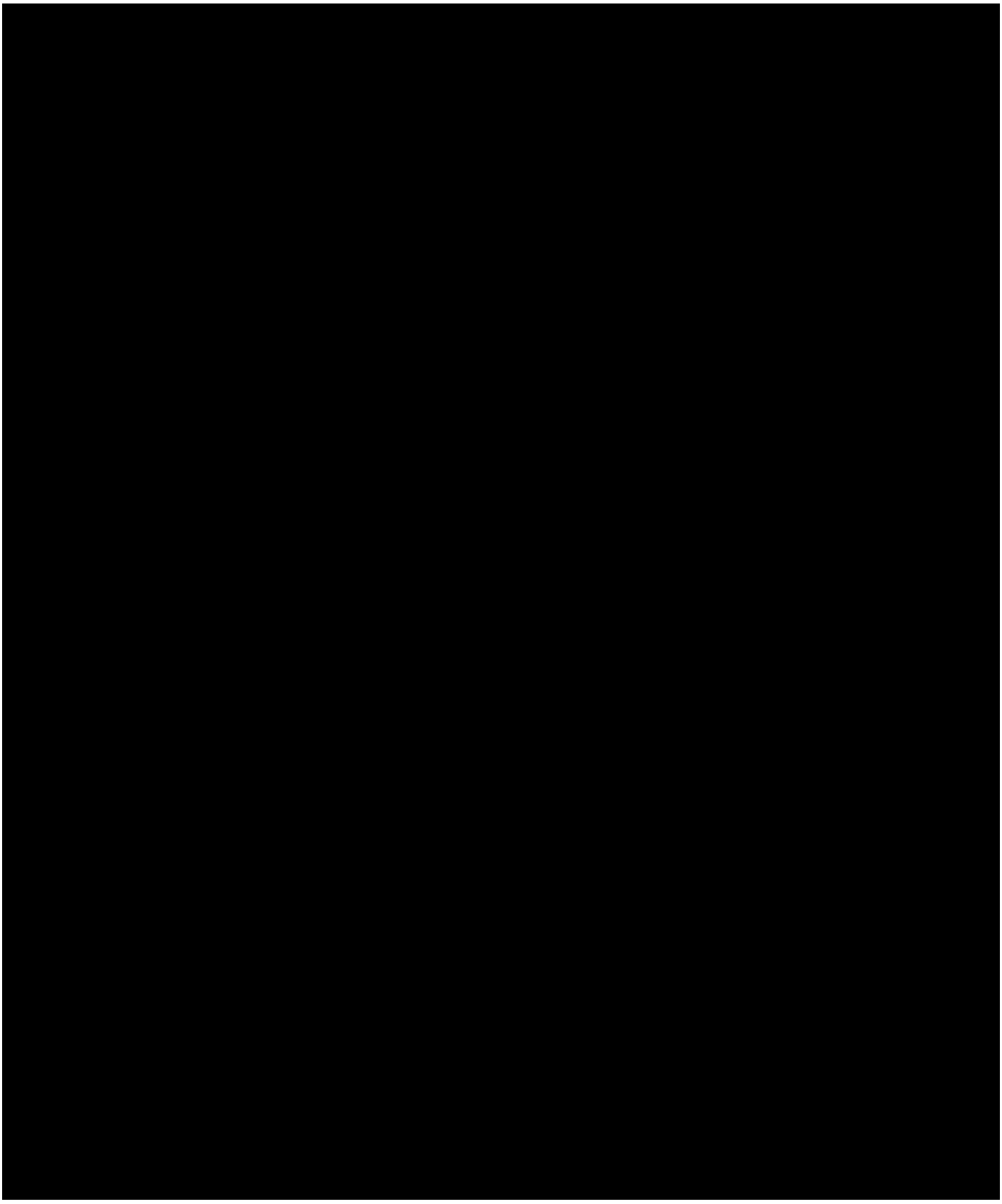
Each 40" MHPS steel blade is twisted with a "root end" that connects it to the hub, a snubber at the mid-point or mid-span, and a shroud with airfoil tips at the top. While the ST spins up to its operating speed of 3600rpm, each blade elongates and starts to untwist. The snubbers and airfoil tips are designed to contact each other and create a stabilizing central and outer ring.

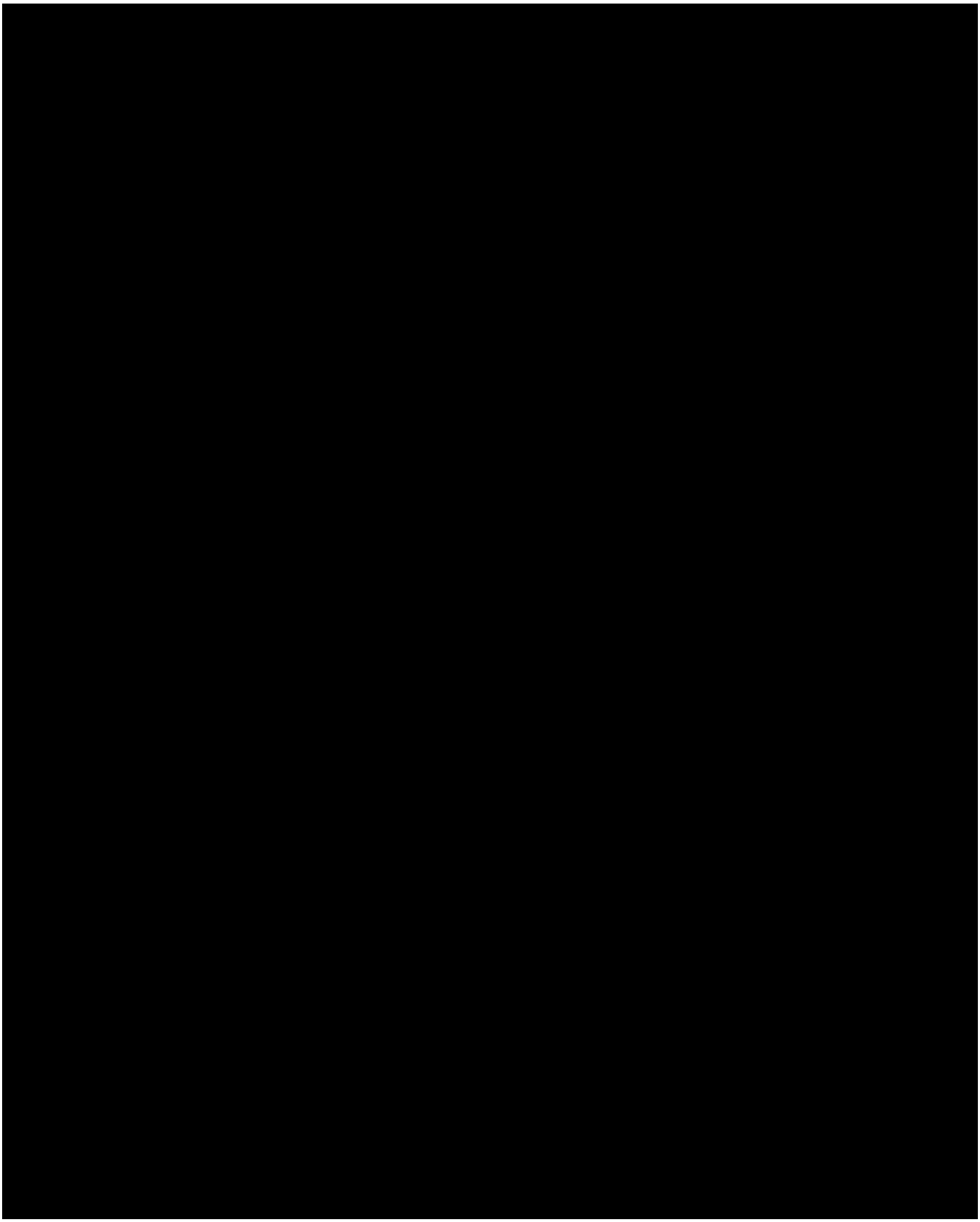
[redacted]

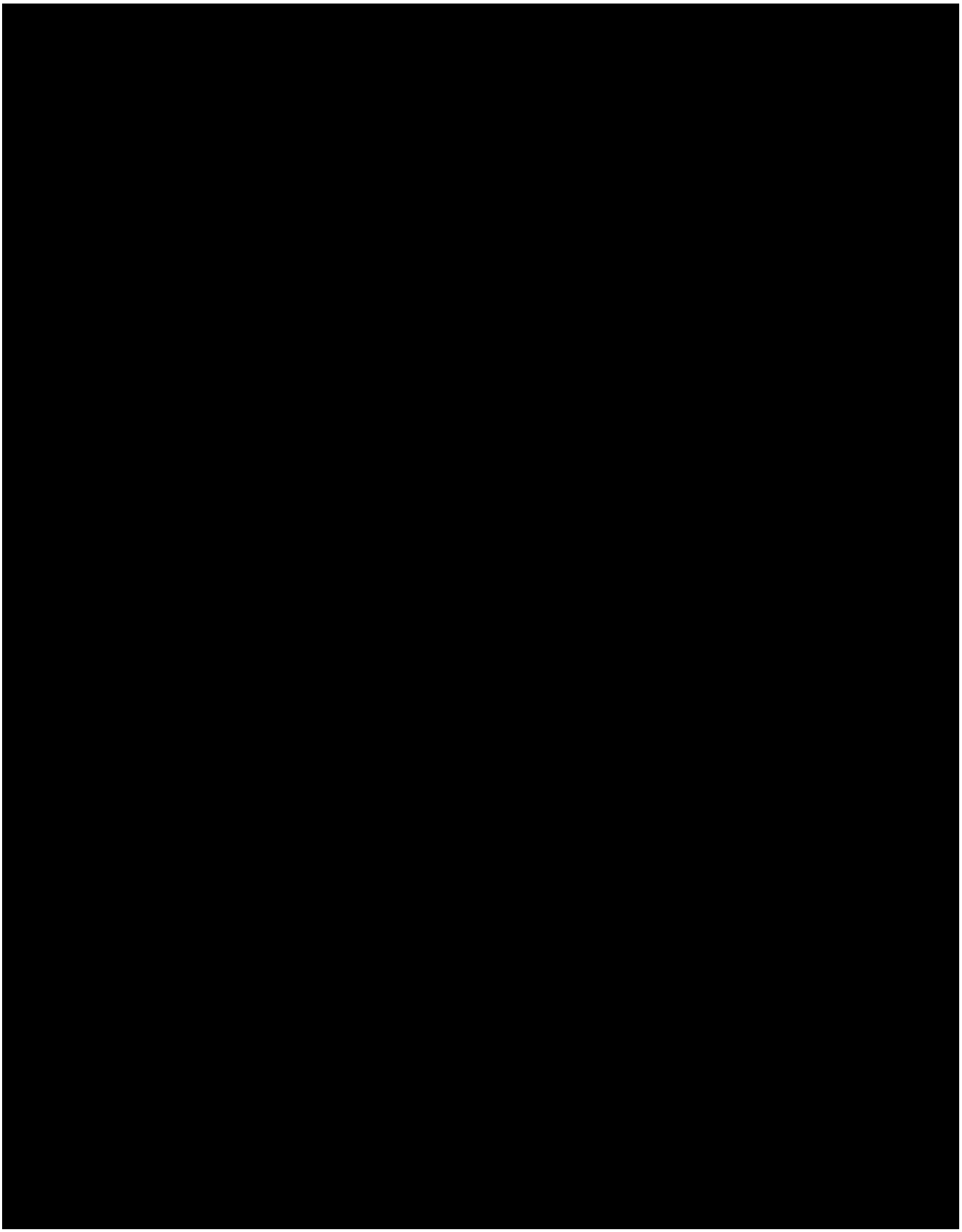
Table A: Bartow L-0 Events Summary

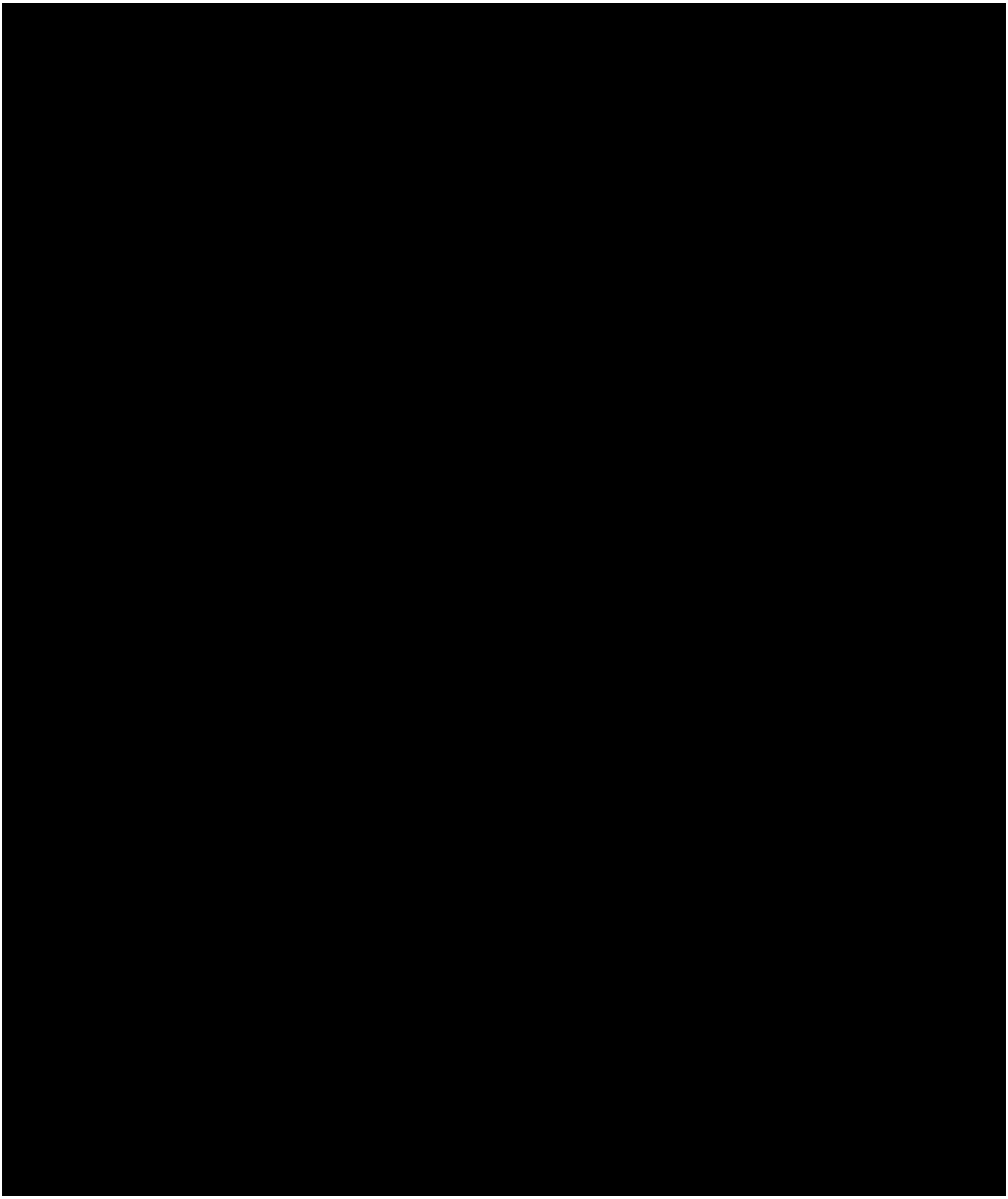
	Period 1	Period 2	Period 3	Period 4	Period 5
Date	June 2009 to March 2012	April 2012 to August 2014	December 2014 to April 2016	May 2016 to Oct 2016	December 2016 to February 2017
Service Duration	~34 Months	~28 Months	~17 Months	~5 Months	~2 Months
[redacted]					
Information Shared with MHPS	Duke provided all requested PI data.	Duke provided all requested PI data.	Duke provided all requested PI data.	Duke provided all requested PI data.	Duke provided all requested PI data.

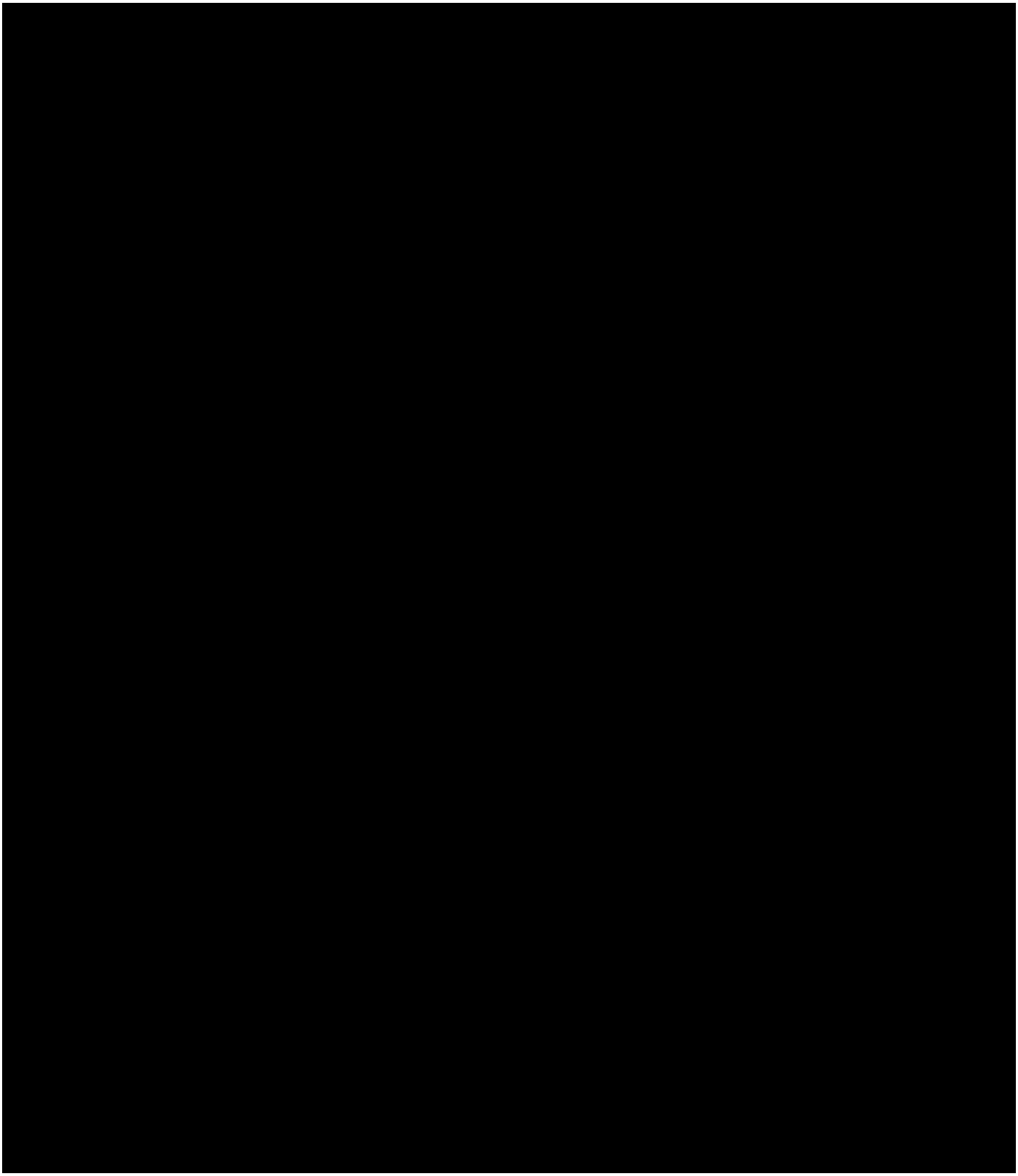
[redacted]

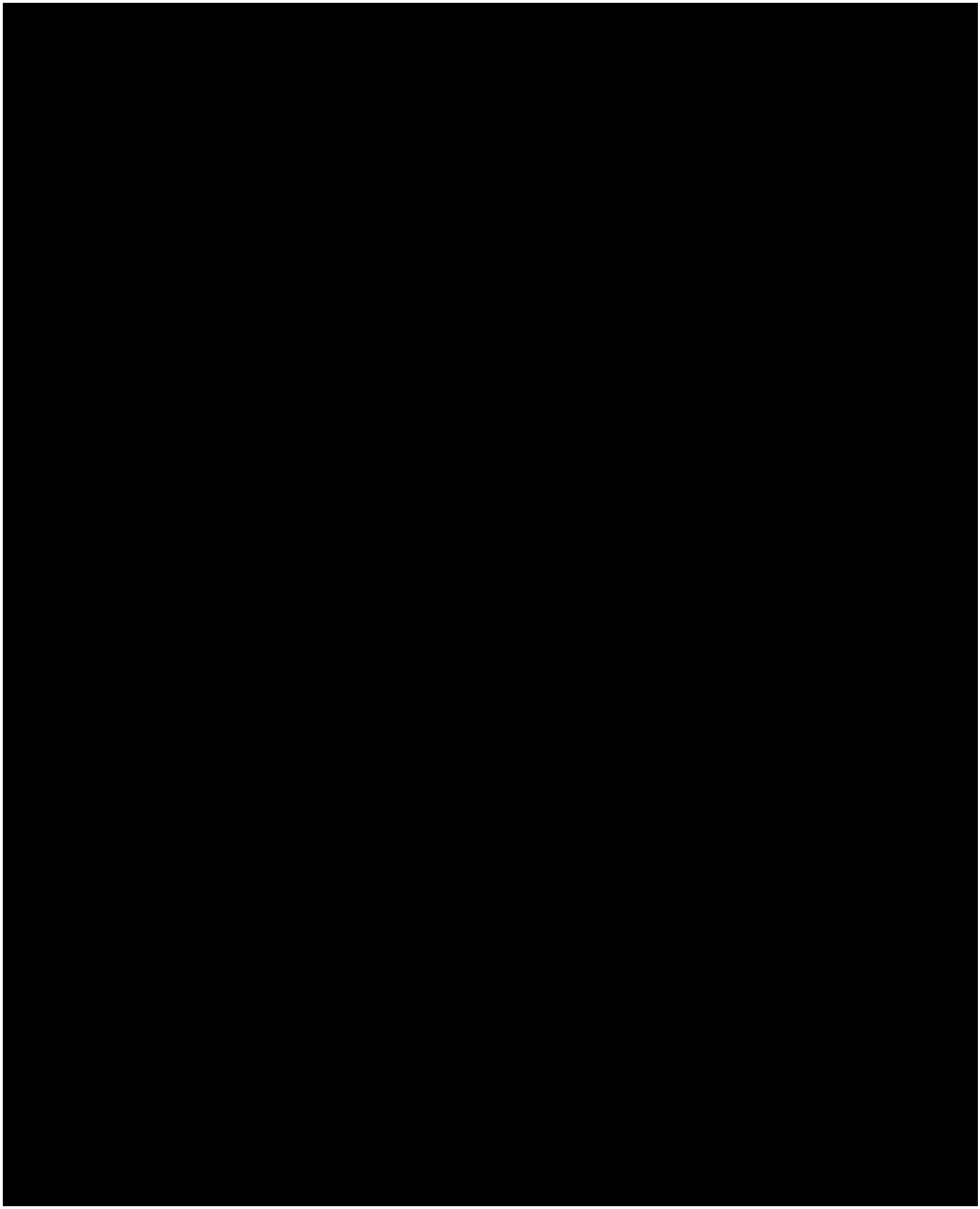


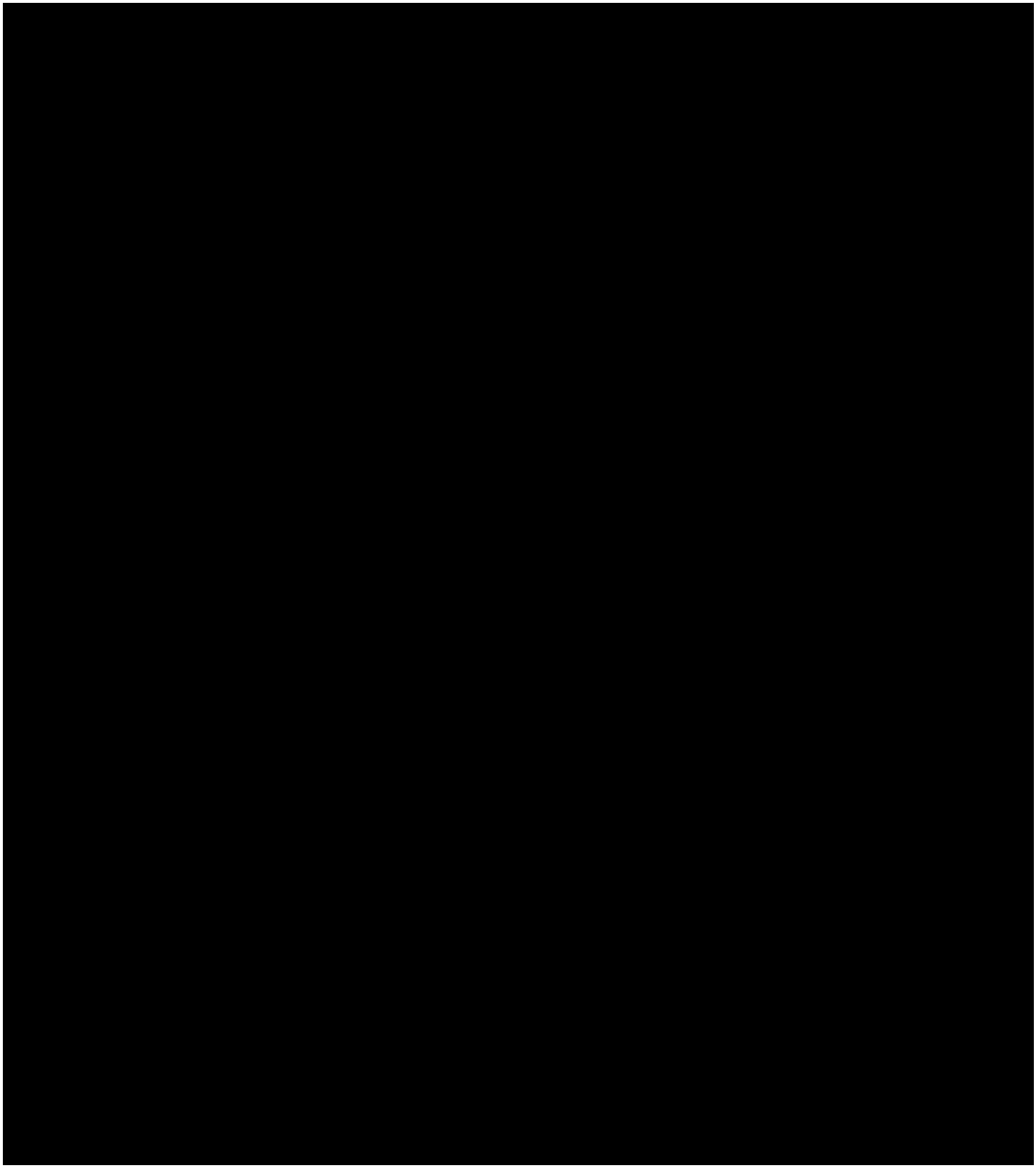




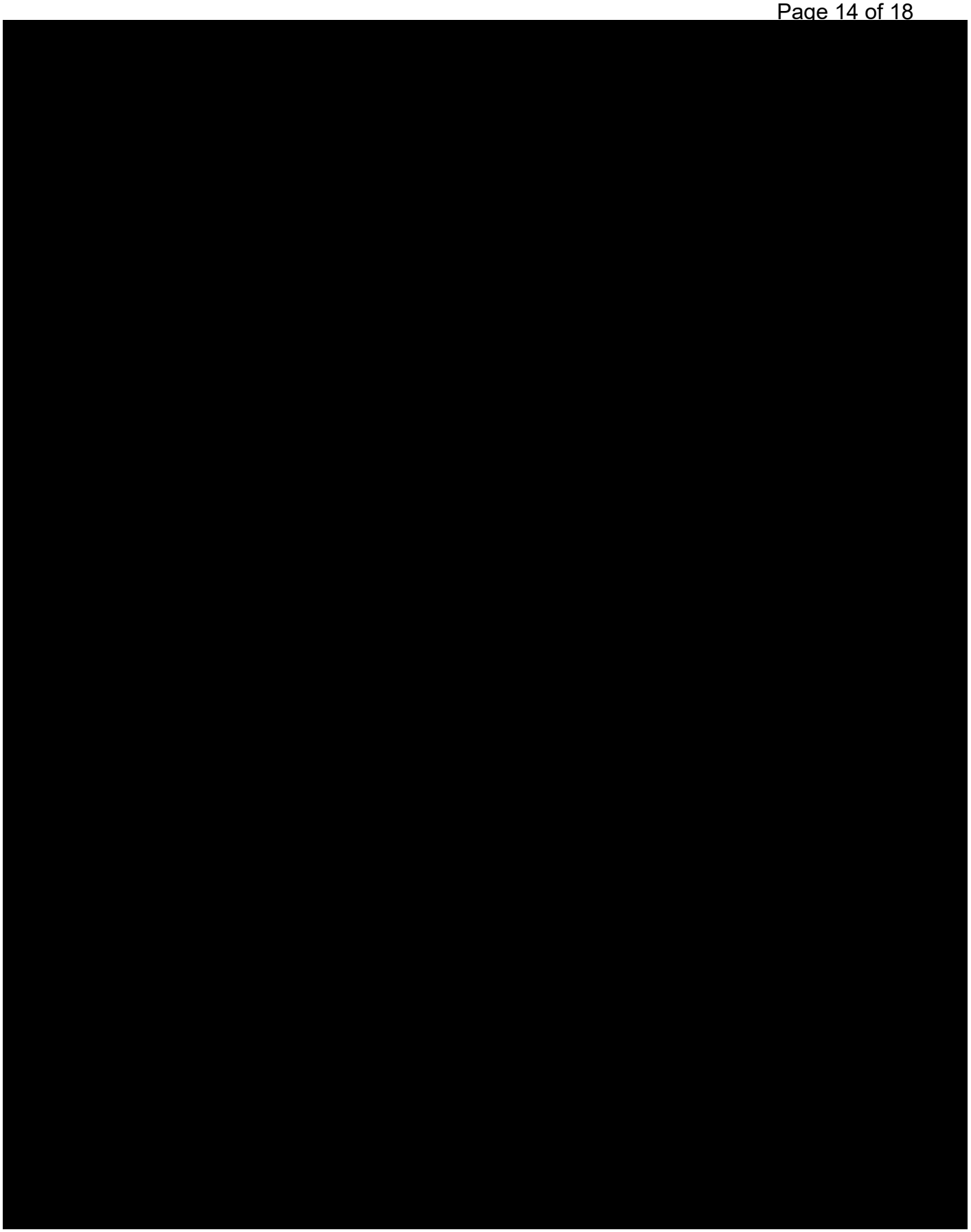














CONCLUSION:



[redacted] This RCA report is Duke's product and presents its view of the root cause based on all inputs received.





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

REDACTED
In its entirety

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 9
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: Arnold Garcia AG-1

REDACTED

Duke Energy Florida

Natural Gas Hedging Detail

Natural Gas	Savings/(Cost) on Hedges			Hedged Volumes (MMBtu's)						
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Actual Burn (Generation & Tolling)	Hedged Burns	% Hedged with Financial	% Hedged with Physical
Jan-18	[redacted]						18,973,500	[redacted]		
Feb-18							13,781,600			
Mar-18							16,635,200			
Apr-18							18,177,700			
May-18							20,503,800			
Jun-18							23,765,300			
Jul-18							27,055,900			
Aug-18							25,052,700			
Sep-18							25,294,300			
Oct-18							21,524,000			
Nov-18							18,528,600			
Dec-18							17,125,400			
YTD	$588,460	$0	$588,460	58,790,000	0	58,790,000	246,418,000	24%	100%	0%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 10
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: James McClay JM-1T

DEF Gas Hedging Status
REDACTED

As of December 31, 2018

Physical/ Financial	Instrument	Put/Call	Month	Trade Number	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	Financial Option	Call	1/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3385718	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3385718	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3386306	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3386306	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Call	1/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Option	Put	1/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$2.7380			
Financial	Financial Swap		1/1/2018	3323577	JPMorganChase Bank E	IFERC	Henry Hub			$2.7400			
Financial	Financial Swap		1/1/2018	3324359	JPMorganChase Bank E	IFERC	Henry Hub			$2.7400			
Financial	Financial Swap		1/1/2018	3325421	MerrilL ynchCom E EM	IFERC	Henry Hub			$2.7400			
Financial	Financial Swap		1/1/2018	3326587	MerrilL ynchCom E EM	IFERC	Henry Hub			$2.7400			
Financial	Financial Swap		1/1/2018	3330751	JPMorganChase Bank E	IFERC	Henry Hub			$2.7400			
Financial	Financial Swap		1/1/2018	3331416	Macquarie Bank Ltd	IFERC	Transco Zone 4			$2.7200			
Financial	Financial Swap		1/1/2018	3332727	Citigroup Energy E	IFERC	Columbia Gulf			$2.6100			
Financial	Financial Swap		1/1/2018	3334113	MerrilL ynchCom E EM	IFERC	Transco Zone 4			$2.7200			
Financial	Financial Swap		1/1/2018	3338316	MerrilL ynchCom E EM	IFERC	Columbia Gulf			$2.6100			
Financial	Financial Swap		1/1/2018	3339657	MerrilL ynchCom E EM	IFERC	Transco Zone 4			$2.7200			
Financial	Financial Swap		1/1/2018	3341152	JPMorganChase Bank E	IFERC	Transco Zone 4			$2.7200			
Financial	Financial Swap		1/1/2018	3342335	MerrilL ynchCom E EM	IFERC	Transco Zone 4			$2.7200			

Financial	Financial Swap		1/1/2018	3343031	Macquarie Bank Ltd	IFERC	Transco Zone 4	[redacted]	$2.7200	[redacted]	
Financial	Financial Swap		1/1/2018	3345065	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3346065	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3347634	BKMONTREAL	IFERC	Columbia Gulf		$2.6100		
Financial	Financial Swap		1/1/2018	3351116	Citigroup Energy E	IFERC	Columbia Gulf		$2.6100		
Financial	Financial Swap		1/1/2018	3352222	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3353475	Scotia Bank	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3354169	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3356327	Citigroup Energy E	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3356823	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3359878	Scotia Bank	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3362877	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3366698	Scotia Bank	IFERC	Transco Zone 4		$2.7200		
Financial	Financial Swap		1/1/2018	3368104	Scotia Bank	IFERC	Transco Zone 4		$2.7200		
		1/1/2018 Total								18,973,500	

								[redacted]		[redacted]	[redacted]
Financial	Financial Option	Call	2/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3385718	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3385718	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3386306	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3386306	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Call	2/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Option	Put	2/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.6310		
Financial	Financial Swap		2/1/2018	3323577	JPMorganChase Bank E	IFERC	Henry Hub		$3.6400		
Financial	Financial Swap		2/1/2018	3324359	JPMorganChase Bank E	IFERC	Henry Hub		$3.6400		
Financial	Financial Swap		2/1/2018	3325421	MerrilL ynchCom E EM	IFERC	Henry Hub		$3.6400		
Financial	Financial Swap		2/1/2018	3326587	MerrilL ynchCom E EM	IFERC	Henry Hub		$3.6400		
Financial	Financial Swap		2/1/2018	3330751	JPMorganChase Bank E	IFERC	Henry Hub		$3.6400		
Financial	Financial Swap		2/1/2018	3331416	Macquarie Bank Ltd	IFERC	Transco Zone 4		$3.7200		
Financial	Financial Swap		2/1/2018	3332727	Citigroup Energy E	IFERC	Columbia Gulf		$3.4900		
Financial	Financial Swap		2/1/2018	3334113	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$3.7200		
Financial	Financial Swap		2/1/2018	3338316	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$3.4900		
Financial	Financial Swap		2/1/2018	3339657	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$3.7200		
Financial	Financial Swap		2/1/2018	3341152	JPMorganChase Bank E	IFERC	Transco Zone 4		$3.7200		
Financial	Financial Swap		2/1/2018	3342335	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$3.7200		
Financial	Financial Swap		2/1/2018	3343031	Macquarie Bank Ltd	IFERC	Transco Zone 4		$3.7200		
Financial	Financial Swap		2/1/2018	3345065	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$3.7200		
Financial	Financial Swap		2/1/2018	3346065	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$3.7200		
Financial	Financial Swap		2/1/2018	3347634	BKMONTREAL	IFERC	Columbia Gulf		$3.4900		
Financial	Financial Swap		2/1/2018	3351116	Citigroup Energy E	IFERC	Columbia Gulf		$3.4900		

									[redacted]		[redacted]		[redacted]
Financial	Financial Swap		2/1/2018	3352222	MerrilL ynchCom E EM	IFERC	Transco Zone 4			$3.7200			
Financial	Financial Swap		2/1/2018	3353475	Scotia Bank	IFERC	Transco Zone 4			$3.7200			
Financial	Financial Swap		2/1/2018	3354169	JPMorganChase Bank E	IFERC	Transco Zone 4			$3.7200			
Financial	Financial Swap		2/1/2018	3356327	Citigroup Energy E	IFERC	Transco Zone 4			$3.7200			
Financial	Financial Swap		2/1/2018	3356823	MerrilL ynchCom E EM	IFERC	Transco Zone 4			$3.7200			
Financial	Financial Swap		2/1/2018	3359878	Scotia Bank	IFERC	Transco Zone 4			$3.7200			
Financial	Financial Swap		2/1/2018	3362877	MerrilL ynchCom E EM	IFERC	Transco Zone 4			$3.7200			
Financial	Financial Swap		2/1/2018	3366698	Scotia Bank	IFERC	Transco Zone 4			$3.7200			
Financial	Financial Swap		2/1/2018	3368104	Scotia Bank	IFERC	Transco Zone 4			$3.7200			
		2/1/2018 Total										13,781,600	

Financial	Financial Option	Call	3/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub	[redacted]	$2.6390	[redacted]	
Financial	Financial Option	Put	3/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3385718	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3385718	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3386306	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3386306	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Call	3/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Option	Put	3/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6390		
Financial	Financial Swap		3/1/2018	3323577	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		3/1/2018	3324359	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		3/1/2018	3325421	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		3/1/2018	3326587	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		3/1/2018	3330751	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		3/1/2018	3331416	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3332727	Citigroup Energy E	IFERC	Columbia Gulf		$2.4900		
Financial	Financial Swap		3/1/2018	3334113	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3338316	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.4900		
Financial	Financial Swap		3/1/2018	3339657	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3341152	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3342335	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3343031	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3345065	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3346065	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3347634	BKMONTREAL	IFERC	Columbia Gulf		$2.4900		
Financial	Financial Swap		3/1/2018	3351116	Citigroup Energy E	IFERC	Columbia Gulf		$2.4900		

Financial	Financial Swap		3/1/2018	3352222	MerrilL ynchCom E EM	IFERC	Transco Zone 4	[redacted]	$2.6200	[redacted]	
Financial	Financial Swap		3/1/2018	3353475	Scotia Bank	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3354169	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3356327	Citigroup Energy E	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3356823	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3359878	Scotia Bank	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3362877	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3366698	Scotia Bank	IFERC	Transco Zone 4		$2.6200		
Financial	Financial Swap		3/1/2018	3368104	Scotia Bank	IFERC	Transco Zone 4		$2.6200		
		3/1/2018 Total								16,635,200	

								[redacted]		[redacted]	[redacted]
Financial	Financial Option	Call	4/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Call	4/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Option	Put	4/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.6910		
Financial	Financial Swap		4/1/2018	3358456	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6900		
Financial	Financial Swap		4/1/2018	3358670	Scotia Bank	IFERC	Henry Hub		$2.6900		
Financial	Financial Swap		4/1/2018	3359030	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6900		
Financial	Financial Swap		4/1/2018	3359877	BKMONTREAL	IFERC	Henry Hub		$2.6900		
Financial	Financial Swap		4/1/2018	3360276	Morgan Stanley E	IFERC	Henry Hub		$2.6900		
Financial	Financial Swap		4/1/2018	3362876	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6900		
Financial	Financial Swap		4/1/2018	3363535	BKMONTREAL	IFERC	Henry Hub		$2.6900		
Financial	Financial Swap		4/1/2018	3363994	Morgan Stanley E	IFERC	Henry Hub		$2.6900		
Financial	Financial Swap		4/1/2018	3366697	Morgan Stanley E	IFERC	Transco Zone 4		$2.6500		
Financial	Financial Swap		4/1/2018	3368103	Morgan Stanley E	IFERC	Transco Zone 4		$2.6500		
Financial	Financial Swap		4/1/2018	3378419	Scotia Bank	IFERC	Transco Zone 4		$2.6500		
Financial	Financial Swap		4/1/2018	3383858	Morgan Stanley E	IFERC	Transco Zone 4		$2.6500		
Financial	Financial Swap		4/1/2018	3389540	Scotia Bank	IFERC	Columbia Gulf		$2.5500		

Financial	Financial Swap		4/1/2018	3400237	BKMONTREAL	IFERC	Columbia Gulf	[redacted]	$2.5500	[redacted]		[redacted]
Financial	Financial Swap		4/1/2018	3406660	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.5500			
		4/1/2018 Total									18,177,700	

Financial	Financial Option	Call	5/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8210	[redacted]	[redacted]
Financial	Financial Option	Put	5/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Call	5/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Option	Put	5/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.8210		
Financial	Financial Swap		5/1/2018	3358456	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		5/1/2018	3358670	Scotia Bank	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		5/1/2018	3359030	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		5/1/2018	3359877	BKMONTREAL	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		5/1/2018	3360276	Morgan Stanley E	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		5/1/2018	3362876	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		5/1/2018	3363535	BKMONTREAL	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		5/1/2018	3363994	Morgan Stanley E	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		5/1/2018	3366697	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		5/1/2018	3368103	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		5/1/2018	3378419	Scotia Bank	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		5/1/2018	3383858	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		5/1/2018	3389540	Scotia Bank	IFERC	Columbia Gulf		$2.6700		

Financial	Financial Swap		5/1/2018	3400237	BKMONTREAL	IFERC	Columbia Gulf	[redacted]	$2.6700	[redacted]		[redacted]
Financial	Financial Swap		5/1/2018	3406660	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.6700			
		5/1/2018 Total									20,503,800	

Financial	Financial Option	Call	6/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8750	[redacted]	
Financial	Financial Option	Put	6/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Call	6/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Option	Put	6/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.8750		
Financial	Financial Swap		6/1/2018	3358456	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8800		
Financial	Financial Swap		6/1/2018	3358670	Scotia Bank	IFERC	Henry Hub		$2.8800		
Financial	Financial Swap		6/1/2018	3359030	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8800		
Financial	Financial Swap		6/1/2018	3359877	BKMONTREAL	IFERC	Henry Hub		$2.8800		
Financial	Financial Swap		6/1/2018	3360276	Morgan Stanley E	IFERC	Henry Hub		$2.8800		
Financial	Financial Swap		6/1/2018	3362876	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8800		
Financial	Financial Swap		6/1/2018	3363535	BKMONTREAL	IFERC	Henry Hub		$2.8800		
Financial	Financial Swap		6/1/2018	3363994	Morgan Stanley E	IFERC	Henry Hub		$2.8800		
Financial	Financial Swap		6/1/2018	3366697	Morgan Stanley E	IFERC	Transco Zone 4		$2.8400		
Financial	Financial Swap		6/1/2018	3368103	Morgan Stanley E	IFERC	Transco Zone 4		$2.8400		
Financial	Financial Swap		6/1/2018	3378419	Scotia Bank	IFERC	Transco Zone 4		$2.8400		
Financial	Financial Swap		6/1/2018	3383858	Morgan Stanley E	IFERC	Transco Zone 4		$2.8400		
Financial	Financial Swap		6/1/2018	3389540	Scotia Bank	IFERC	Columbia Gulf		$2.7200		

Financial	Financial Swap		6/1/2018	3400237	BKMONTREAL	IFERC	Columbia Gulf	[redacted]	$2.7200	[redacted]		[redacted]
Financial	Financial Swap		6/1/2018	3406660	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.7200			
		6/1/2018 Total									23,765,300	

								[redacted]		[redacted]	[redacted]
Financial	Financial Option	Call	7/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Call	7/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Option	Put	7/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.9960		
Financial	Financial Swap		7/1/2018	3358456	MerrilL ynchCom E EM	IFERC	Henry Hub		$3.0000		
Financial	Financial Swap		7/1/2018	3358670	Scotia Bank	IFERC	Henry Hub		$3.0000		
Financial	Financial Swap		7/1/2018	3359030	MerrilL ynchCom E EM	IFERC	Henry Hub		$3.0000		
Financial	Financial Swap		7/1/2018	3359877	BKMONTREAL	IFERC	Henry Hub		$3.0000		
Financial	Financial Swap		7/1/2018	3360276	Morgan Stanley E	IFERC	Henry Hub		$3.0000		
Financial	Financial Swap		7/1/2018	3362876	MerrilL ynchCom E EM	IFERC	Henry Hub		$3.0000		
Financial	Financial Swap		7/1/2018	3363535	BKMONTREAL	IFERC	Henry Hub		$3.0000		
Financial	Financial Swap		7/1/2018	3363994	Morgan Stanley E	IFERC	Henry Hub		$3.0000		
Financial	Financial Swap		7/1/2018	3366697	Morgan Stanley E	IFERC	Transco Zone 4		$2.9600		
Financial	Financial Swap		7/1/2018	3368103	Morgan Stanley E	IFERC	Transco Zone 4		$2.9600		
Financial	Financial Swap		7/1/2018	3378419	Scotia Bank	IFERC	Transco Zone 4		$2.9600		
Financial	Financial Swap		7/1/2018	3383858	Morgan Stanley E	IFERC	Transco Zone 4		$2.9600		
Financial	Financial Swap		7/1/2018	3389540	Scotia Bank	IFERC	Columbia Gulf		$2.8400		

Financial	Financial Swap		7/1/2018	3400237	BKMONTREAL	IFERC	Columbia Gulf	[redacted]	$2.8400	[redacted]	
Financial	Financial Swap		7/1/2018	3406660	Macquarie Bank Ltd	IFERC	Columbia Gulf	[redacted]	$2.8400	[redacted]	
		7/1/2018 Total						[redacted]		[redacted]	27,055,900

								[redacted]			
Financial	Financial Option	Call	8/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Call	8/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Option	Put	8/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.8220		
Financial	Financial Swap		8/1/2018	3358456	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		8/1/2018	3358670	Scotia Bank	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		8/1/2018	3359030	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		8/1/2018	3359877	BKMONTREAL	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		8/1/2018	3360276	Morgan Stanley E	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		8/1/2018	3362876	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		8/1/2018	3363535	BKMONTREAL	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		8/1/2018	3363994	Morgan Stanley E	IFERC	Henry Hub		$2.8200		
Financial	Financial Swap		8/1/2018	3366697	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		8/1/2018	3368103	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		8/1/2018	3378419	Scotia Bank	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		8/1/2018	3383858	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		8/1/2018	3389540	Scotia Bank	IFERC	Columbia Gulf		$2.6800		

Financial	Financial Swap		8/1/2018	3400237	BKMONTREAL	IFERC	Columbia Gulf	[redacted]	$2.6800	[redacted]		
Financial	Financial Swap		8/1/2018	3406660	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.6800			[redacted]
		8/1/2018 Total									25,052,700	

								[redacted]		[redacted]	[redacted]
Financial	Financial Option	Call	9/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Call	9/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Option	Put	9/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.8950		
Financial	Financial Swap		9/1/2018	3358456	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9000		
Financial	Financial Swap		9/1/2018	3358670	Scotia Bank	IFERC	Henry Hub		$2.9000		
Financial	Financial Swap		9/1/2018	3359030	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9000		
Financial	Financial Swap		9/1/2018	3359877	BKMONTREAL	IFERC	Henry Hub		$2.9000		
Financial	Financial Swap		9/1/2018	3360276	Morgan Stanley E	IFERC	Henry Hub		$2.9000		
Financial	Financial Swap		9/1/2018	3362876	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9000		
Financial	Financial Swap		9/1/2018	3363535	BKMONTREAL	IFERC	Henry Hub		$2.9000		
Financial	Financial Swap		9/1/2018	3363994	Morgan Stanley E	IFERC	Henry Hub		$2.9000		
Financial	Financial Swap		9/1/2018	3366697	Morgan Stanley E	IFERC	Transco Zone 4		$2.8700		
Financial	Financial Swap		9/1/2018	3368103	Morgan Stanley E	IFERC	Transco Zone 4		$2.8700		
Financial	Financial Swap		9/1/2018	3378419	Scotia Bank	IFERC	Transco Zone 4		$2.8700		
Financial	Financial Swap		9/1/2018	3383858	Morgan Stanley E	IFERC	Transco Zone 4		$2.8700		
Financial	Financial Swap		9/1/2018	3389540	Scotia Bank	IFERC	Columbia Gulf		$2.7600		

Financial	Financial Swap		9/1/2018	3400237	BKMONTREAL	IFERC	Columbia Gulf	[redacted]	$2.7600	[redacted]		[redacted]
Financial	Financial Swap		9/1/2018	3406660	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.7600			
		9/1/2018 Total									25,294,300	

Financial	Financial Option	Call	10/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub	[redacted]	$3.0210	[redacted]	[redacted]
Financial	Financial Option	Put	10/1/2018	3364488	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3364878	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3441943	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Call	10/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Option	Put	10/1/2018	3442960	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$3.0210		
Financial	Financial Swap		10/1/2018	3358456	MerrilL ynchCom E EM	IFERC	Henry Hub		$3.0200		
Financial	Financial Swap		10/1/2018	3358670	Scotia Bank	IFERC	Henry Hub		$3.0200		
Financial	Financial Swap		10/1/2018	3359030	MerrilL ynchCom E EM	IFERC	Henry Hub		$3.0200		
Financial	Financial Swap		10/1/2018	3359877	BKMONTREAL	IFERC	Henry Hub		$3.0200		
Financial	Financial Swap		10/1/2018	3360276	Morgan Stanley E	IFERC	Henry Hub		$3.0200		
Financial	Financial Swap		10/1/2018	3362876	MerrilL ynchCom E EM	IFERC	Henry Hub		$3.0200		
Financial	Financial Swap		10/1/2018	3363535	BKMONTREAL	IFERC	Henry Hub		$3.0200		
Financial	Financial Swap		10/1/2018	3363994	Morgan Stanley E	IFERC	Henry Hub		$3.0200		
Financial	Financial Swap		10/1/2018	3366697	Morgan Stanley E	IFERC	Transco Zone 4		$2.9700		
Financial	Financial Swap		10/1/2018	3368103	Morgan Stanley E	IFERC	Transco Zone 4		$2.9700		
Financial	Financial Swap		10/1/2018	3378419	Scotia Bank	IFERC	Transco Zone 4		$2.9700		
Financial	Financial Swap		10/1/2018	3383858	Morgan Stanley E	IFERC	Transco Zone 4		$2.9700		
Financial	Financial Swap		10/1/2018	3389540	Scotia Bank	IFERC	Columbia Gulf		$2.8400		

Financial	Financial Swap		10/1/2018	3400237	BKMONTREAL	IFERC	Columbia Gulf	[redacted]	$2.8400	[redacted]	
Financial	Financial Swap		10/1/2018	3406660	Macquarie Bank Ltd	IFERC	Columbia Gulf	[redacted]	$2.8400	[redacted]	[redacted]
		10/1/2018 Total						[redacted]		[redacted]	21,524,000

Financial	Financial Option	Call	11/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub	[redacted]	$3.1850	[redacted]	[redacted]
Financial	Financial Option	Put	11/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Call	11/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Option	Put	11/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$3.1850		
Financial	Financial Swap		11/1/2018	3407033	BKMONTREAL	IFERC	Henry Hub		$3.1900		
Financial	Financial Swap		11/1/2018	3407887	Citigroup Energy E	IFERC	Henry Hub		$3.1900		
Financial	Financial Swap		11/1/2018	3409077	JPMorganChase Bank E	IFERC	Henry Hub		$3.1900		
Financial	Financial Swap		11/1/2018	3411171	MerrilL ynchCom E EM	IFERC	Henry Hub		$3.1900		
Financial	Financial Swap		11/1/2018	3412832	Scotia Bank	IFERC	Henry Hub		$3.1900		
Financial	Financial Swap		11/1/2018	3413590	BKMONTREAL	IFERC	Henry Hub		$3.1900		
Financial	Financial Swap		11/1/2018	3415207	Citigroup Energy E	IFERC	Henry Hub		$3.1900		
			11/1/2018 Total								18,528,600
Financial	Financial Option	Call	12/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3369582	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3370825	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3374394	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3375609	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3377269	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3378618	BKMONTREAL	NYMEX NG L1D	Henry Hub		$4.7150		

Financial	Financial Option	Call	12/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub	[redacted]	$4.7150	[redacted]	[redacted]
Financial	Financial Option	Put	12/1/2018	3380906	BKMONTREAL	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3382162	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3383110	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3385147	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3387637	BKMONTREAL	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3389134	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Call	12/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Option	Put	12/1/2018	3399703	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$4.7150		
Financial	Financial Swap		12/1/2018	3407033	BKMONTREAL	IFERC	Henry Hub		$4.7400		
Financial	Financial Swap		12/1/2018	3407887	Citigroup Energy E	IFERC	Henry Hub		$4.7400		
Financial	Financial Swap		12/1/2018	3409077	JPMorganChase Bank E	IFERC	Henry Hub		$4.7400		
Financial	Financial Swap		12/1/2018	3411171	MerrilL ynchCom E EM	IFERC	Henry Hub		$4.7400		
Financial	Financial Swap		12/1/2018	3412832	Scotia Bank	IFERC	Henry Hub		$4.7400		
Financial	Financial Swap		12/1/2018	3413590	BKMONTREAL	IFERC	Henry Hub		$4.7400		
Financial	Financial Swap		12/1/2018	3415207	Citigroup Energy E	IFERC	Henry Hub		$4.7400		
		12/1/2018 Total								17,125,400	

REDACTED

CONFIDENTIAL

Duke Energy Florida

Natural Gas Hedging Detail

Natural Gas	Savings/(Cost) on Hedges			Hedged Volumes (MMBtu's)						
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Actual Burn (Generation & Tolling)	Hedged Burns	% Hedged with Financial	% Hedged with Physical
Jan-19	[redacted]						19,812,300	[redacted]		
Feb-19							18,424,800			
Mar-19							17,991,900			
YTD	$100,700	$0	$100,700	3,150,000	0	3,150,000	56,229,000	6%	100%	0%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 11
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: James McClay JM-1P

REDACTED

DEF Gas Hedging Status
CONFIDENTIAL

As of March 31, 2019

Physical/ Financial	Instrument	Put/Call	Month	Trade Number	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	Financial Swap		1/1/2019	3413590	BKMONTREAL	IFERC	Henry Hub	[redacted]	[redacted]	$3.6500	[redacted]		
Financial	Financial Swap		1/1/2019	3407033	BKMONTREAL	IFERC	Henry Hub			$3.6500			
Financial	Financial Swap		1/1/2019	3415207	Citigroup Energy E	IFERC	Henry Hub			$3.6500			
Financial	Financial Swap		1/1/2019	3407887	Citigroup Energy E	IFERC	Henry Hub			$3.6500			
Financial	Financial Swap		1/1/2019	3409077	JPMorganChase Bank E	IFERC	Henry Hub			$3.6500			
Financial	Financial Swap		1/1/2019	3411171	MerrilL ynchCom E EM	IFERC	Henry Hub			$3.6500			
Financial	Financial Swap		1/1/2019	3412832	Scotia Bank	IFERC	Henry Hub			$3.6500			
			1/1/2019 Total									19,812,300	[redacted]
Financial	Financial Swap		2/1/2019	3413590	BKMONTREAL	IFERC	Henry Hub			$2.9500			
Financial	Financial Swap		2/1/2019	3407033	BKMONTREAL	IFERC	Henry Hub			$2.9500			
Financial	Financial Swap		2/1/2019	3415207	Citigroup Energy E	IFERC	Henry Hub			$2.9500			
Financial	Financial Swap		2/1/2019	3407887	Citigroup Energy E	IFERC	Henry Hub			$2.9500			
Financial	Financial Swap		2/1/2019	3409077	JPMorganChase Bank E	IFERC	Henry Hub			$2.9500			
Financial	Financial Swap		2/1/2019	3411171	MerrilL ynchCom E EM	IFERC	Henry Hub			$2.9500			
Financial	Financial Swap		2/1/2019	3412832	Scotia Bank	IFERC	Henry Hub			$2.9500			
			2/1/2019 Total									18,424,800	[redacted]
Financial	Financial Swap		3/1/2019	3413590	BKMONTREAL	IFERC	Henry Hub			$2.8600			
Financial	Financial Swap		3/1/2019	3407033	BKMONTREAL	IFERC	Henry Hub			$2.8600			
Financial	Financial Swap		3/1/2019	3415207	Citigroup Energy E	IFERC	Henry Hub			$2.8600			
Financial	Financial Swap		3/1/2019	3407887	Citigroup Energy E	IFERC	Henry Hub			$2.8600			
Financial	Financial Swap		3/1/2019	3409077	JPMorganChase Bank E	IFERC	Henry Hub			$2.8600			
Financial	Financial Swap		3/1/2019	3411171	MerrilL ynchCom E EM	IFERC	Henry Hub			$2.8600			
Financial	Financial Swap		3/1/2019	3412832	Scotia Bank	IFERC	Henry Hub			$2.8600			
			3/1/2019 Total									17,991,900	[redacted]

GPIF REWARD/PENALTY SCHEDULES

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 12
PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: James B. Daniel JBD-1T

Original Sheet No. 6.101.1

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Duke Energy Florida
January 2018 - December 2018

	Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss ($)	Generating Performance Incentive Factor ($)
	10	$ 52,390,839	$ 19,678,791
	9	$ 47,151,755	$ 17,710,912
	8	$ 41,912,671	$ 15,743,033
	7	$ 36,673,587	$ 13,775,154
	6	$ 31,434,503	$ 11,807,275
	5	$ 26,195,420	$ 9,839,395
	4	$ 20,956,336	$ 7,871,516
	3	$ 15,717,252	$ 5,903,637
	2	$ 10,478,168	$ 3,935,758
****	1.317	$ 6,899,874	$ 2,591,697
	1	$ 5,239,084	$ 1,967,879
	0	$ -	$ -
	-1	$ (6,858,577)	$ (1,967,879)
	-2	$ (13,717,155)	$ (3,935,758)
	-3	$ (20,575,732)	$ (5,903,637)
	-4	$ (27,434,309)	$ (7,871,516)
	-5	$ (34,292,887)	$ (9,839,395)
	-6	$ (41,151,464)	$ (11,807,275)
	-7	$ (48,010,041)	$ (13,775,154)
	-8	$ (54,868,619)	$ (15,743,033)
	-9	$ (61,727,196)	$ (17,710,912)
	-10	$ (68,585,773)	$ (19,678,791)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Duke Energy Florida
January 2018 - December 2018

1	Beginning of period balance of common equity	$ 5,617,924,574	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2018	$ 5,693,033,966	
3	Month of FEBRUARY 2018	$ 5,706,953,234	
4	Month of MARCH 2018	$ 5,722,953,578	
5	Month of APRIL 2018	$ 5,753,601,801	
6	Month of MAY 2018	$ 5,808,897,323	
7	Month of JUNE 2018	$ 5,895,295,848	
8	Month of JULY 2018	$ 5,974,359,096	
9	Month of AUGUST 2018	$ 6,053,238,869	
10	Month of SEPTEMBER 2018	$ 6,054,203,361	
11	Month of OCTOBER 2018	$ 6,106,472,902	
12	Month of NOVEMBER 2018	$ 6,135,962,175	
13	Month of DECEMBER 2018	$ 6,098,448,855	
14	Average common equity for the period	$ 5,893,949,660	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	74.3902%	
17	Maximum allowed incentive dollars	$ 19,807,540	
18	Jurisdictional Sales *	39,144,651	MWH
19	Total Sales *	39,398,824	MWH
20	Jurisdictional Separation Factor	99.3500%	
21	Maximum allowed jurisdictional incentive dollars	$ 19,678,791	
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 6.101.1	$ 26,195,420	
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	$ 19,678,791	

* Net sales (Sales - Interruptible)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Duke Energy Florida
January 2018 - December 2018

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Bartow CC	EAF	3.87	4.822	0.186
	ANOHR	24.53	-2.553	-0.626
Crystal River 4	EAF	2.86	-2.561	-0.073
	ANOHR	10.38	3.718	0.386
Crystal River 5	EAF	2.91	-7.758	-0.226
	ANOHR	12.72	0.000	0.000
Hines 1	EAF	0.48	-9.231	-0.044
	ANOHR	9.08	0.000	0.000
Hines 2	EAF	10.41	10.000	1.041
	ANOHR	3.72	0.000	0.000
Hines 3	EAF	0.98	10.000	0.098
	ANOHR	7.78	0.000	0.000
Hines 4	EAF	5.17	10.000	0.517
	ANOHR	5.11	1.127	0.058
GPIF System		100.00		1.317

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GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Duke Energy Florida
January 2018 - December 2018

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	EAF Adjusted Actual (%)	Estimated Fuel Savings/ Loss ($000)
Bartow CC	3.87	90.20	93.82	82.91	$2,025	($4,591)	91.95	$977
Crystal River 4	2.86	87.06	89.54	82.03	$1,497	($3,877)	85.78	($993)
Crystal River 5	2.91	92.30	94.76	87.26	$1,524	($3,877)	88.39	($3,008)
Hines 1	0.48	92.36	93.25	90.51	$252	($528)	90.65	($487)
Hines 2	10.41	68.97	80.88	44.26	$5,452	($11,127)	92.73	$5,452
Hines 3	0.98	87.04	88.43	84.18	$515	($879)	89.11	$515
Hines 4	5.17	83.25	87.98	73.52	$2,711	($5,292)	92.00	$2,711
GPIF System	26.68				$13,976.3	($30,171.3)		$5,166.6

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (Btu/kwh)	ANOHR RANGE Max. (Btu/kwh)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	ANOHR Adjusted Actual (Btu/kwh)	Estimated Fuel Savings/ Loss ($000)
Bartow CC	24.53	7,916	71.7	7,231	8,600	$12,851	($12,851)	8,146	($3,281)
Crystal River 4	10.38	10,112	80.0	9,688	10,537	$5,439	($5,439)	9,907	$2,022
Crystal River 5	12.72	9,905	80.2	9,427	10,383	$6,665	($6,665)	9,834	$0
Hines 1	9.08	7,314	89.3	6,830	7,797	$4,759	($4,759)	7,318	$0
Hines 2	3.72	7,357	84.5	7,007	7,706	$1,948	($1,948)	7,375	$0
Hines 3	7.78	7,285	83.8	6,861	7,708	$4,074	($4,074)	7,224	$0
Hines 4	5.11	7,066	91.1	6,786	7,346	$2,679	($2,679)	6,968	$302
GPIF System	73.32					$38,414.5	($38,414.5)		($956.7)

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GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida
January 2018 - December 2018

Plant/Unit	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	ADJUSTED ACTUAL EAF %
Bartow CC	91.99	-0.04	91.95
Crystal River 4	81.21	4.57	85.78
Crystal River 5	86.24	2.15	88.39
Hines 1	89.66	0.99	90.65
Hines 2	93.42	-0.68	92.73
Hines 3	90.45	-1.34	89.11
Hines 4	91.92	0.08	92.00

Plant/Unit	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ADJUSTED ACTUAL ANOHR BTU/KWH
Bartow CC	7,664.2	482.0	8,146.2
Crystal River 4	9,985.8	-78.5	9,907.3
Crystal River 5	10,023.1	-189.4	9,833.7
Hines 1	7,314.6	3.0	7,317.6
Hines 2	7,360.2	15.2	7,375.4
Hines 3	7,178.5	45.3	7,223.8
Hines 4	6,955.3	12.6	6,967.9

(1) For documentation of adjustments to actual EAF, see sheet 6.
(2) For documentation of adjustments to actual ANOHR, see sheet 7.

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO EAF ACTUAL

Duke Energy Florida
January 2018 - December 2018

EAF adjustments for Planned Outage Hours			Bartow CC BA4	Crystal River 4 CR4	Crystal River 5 CR5	Hines 1 HN1	Hines 2 HN2	Hines 3 HN3	Hines 4 HN4
1	Actual POH	Hrs.	176.34	1,102.47	423.81	594.13	443.29	757.26	595.43
2	Target POH	Hrs.	180.00	672.00	216.00	504.00	504.00	876.00	588.00
3	Adj. Factor (PH-POHT/PH-POHA)		1.00	1.06	1.02	1.01	0.99	0.99	1 00
4	Actual EUOH	Hrs.	525.74	543.47	781.74	311.81	133.52	78.93	112.28
5	Adj. EUOH (3*4)	Hrs.	525.51	574.02	801.23	315.26	132.54	77.76	112.38
6	Actual EAF	%	91.99	81.21	86.24	89.66	93.42	90.45	91.92
7	Adjusted EAF (using 2 & 5)	%	91.95	85.78	88.39	90.65	92.73	89.11	92.00
8	Difference (7-6)	%	-0.04	4.57	2.15	0.99	-0.68	-1.34	0 08
9	Total adj. to EAF	%	-0.04	4.57	2.15	0.99	-0.68	-1.34	0 08

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO ANOHR ACTUAL

Duke Energy Florida
January 2018 - December 2018

ANOHR adjustments for Target NOF			Bartow CC BA4	Crystal River 4 CR4	Crystal River 5 CR5	Hines 1 HN1	Hines 2 HN2	Hines 3 HN3	Hines 4 HN4
1	Target NOF	%	71.7	80 0	80 2	89 3	84.5	83.8	91.1
2	Target ANOHR	Btu/kwh	7915.6	10112 3	9904 9	7313 9	7356 5	7284.6	7065.9
3	Actual NOF	%	85 6	77.1	73 8	90 2	88.3	88.6	94.0
4	Calc. ANOHR (using 3)	Btu/kwh	7,433 5	10190 8	10,094 3	7,310 9	7,341.3	7,239.3	7,053.4
5	Total adj. to ANOHR (2-4)	Btu/kwh	482.0	-78 5	-189.4	3 0	15.2	45.3	12.6

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2018 - December 2018

Unit: Bartow CC

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$2,025,248	93.82	10	$12,850,566	7,230.8	
	9	$1,822,724	93.46	9	$11,565,509	7,291.8	
	8	$1,620,199	93.10	8	$10,280,453	7,352.8	
	7	$1,417,674	92.73	7	$8,995,396	7,413.8	
	6	$1,215,149	92.37	6	$7,710,339	7,474.7	
	5	$1,012,624	92.01	5	$6,425,283	7,535.7	
****	4.822	$976,575	91.95	4	$5,140,226	7,596.7	
	4	$810,099	91.65	3	$3,855,170	7,657.6	
	3	$607,575	91.29	2	$2,570,113	7,718.6	
	2	$405,050	90.92	1	$1,285,057	7,779.6	
	1	$202,525	90.56	0	$0	7,840.6	
		$0	90.20	0	$0	7,915.6	
	0	$0	90.20	0	$0	7,990.6	
		$0	90.20	-1	($1,285,057)	8,051.5	
	-1	($459,132)	89.47	-2	($2,570,113)	8,112.5	
	-2	($918,265)	88.74	-2.553	($3,280,749)	8,146.2	****
	-3	($1,377,397)	88.01	-3	($3,855,170)	8,173.5	
	-4	($1,836,530)	87.28	-4	($5,140,226)	8,234.4	
	-5	($2,295,662)	86.55	-5	($6,425,283)	8,295.4	
	-6	($2,754,795)	85.82	-6	($7,710,339)	8,356.4	
	-7	($3,213,927)	85.09	-7	($8,995,396)	8,417.3	
	-8	($3,673,059)	84.37	-8	($10,280,453)	8,478.3	
	-9	($4,132,192)	83.64	-9	($11,565,509)	8,539.3	
	-10	($4,591,324)	82.91	-10	($12,850,566)	8,600.3	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.87%	24.53%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2018 - December 2018

Unit: Crystal River 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,497,303	89.54	10	$5,438,836	9,687.6	
	9	$1,347,573	89.29	9	$4,894,952	9,722.6	
	8	$1,197,843	89.04	8	$4,351,069	9,757.6	
	7	$1,048,112	88.79	7	$3,807,185	9,792.5	
	6	$898,382	88.55	6	$3,263,302	9,827.5	
	5	$748,652	88.30	5	$2,719,418	9,862.5	
	4	$598,921	88.05	4	$2,175,534	9,897.4	
	3	$449,191	87.81	3.718	$2,022,159	9,907.3	****
	2	$299,461	87.56	3	$1,631,651	9,932.4	
	1	$149,730	87.31	2	$1,087,767	9,967.4	
		$0	87.06	1	$543,884	10,002.3	
	0	$0	87.06	0	$0	10,037.3	
		$0	87.06	0	$0	10,112.3	
	-1	($387,693)	86.56	0	$0	10,187.3	
	-2	($775,386)	86.06	-1	($543,884)	10,222.3	
****	-2.561	($992,882)	85.78	-2	($1,087,767)	10,257.2	
	-3	($1,163,080)	85.56	-3	($1,631,651)	10,292.2	
	-4	($1,550,773)	85.05	-4	($2,175,534)	10,327.2	
	-5	($1,938,466)	84.55	-5	($2,719,418)	10,362.1	
	-6	($2,326,159)	84.05	-6	($3,263,302)	10,397.1	
	-7	($2,713,852)	83.54	-7	($3,807,185)	10,432.1	
	-8	($3,101,545)	83.04	-8	($4,351,069)	10,467.0	
	-9	($3,489,239)	82.54	-9	($4,894,952)	10,502.0	
	-10	($3,876,932)	82.03	-10	($5,438,836)	10,537.0	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.86%	10.38%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2018 - December 2018

Unit: Crystal River 5

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,523,660	94.76	10	$6,665,454	9,426.8	
	9	$1,371,294	94.51	9	$5,998,908	9,467.1	
	8	$1,218,928	94.27	8	$5,332,363	9,507.4	
	7	$1,066,562	94.02	7	$4,665,818	9,547.8	
	6	$914,196	93.77	6	$3,999,272	9,588.1	
	5	$761,830	93.53	5	$3,332,727	9,628.4	
	4	$609,464	93.28	4	$2,666,181	9,668.7	
	3	$457,098	93.03	3	$1,999,636	9,709.0	
	2	$304,732	92.79	2	$1,333,091	9,749.3	
	1	$152,366	92.54	1	$666,545	9,789.6	
		$0	92.30	0	$0	9,829.9	
	0	$0	92.30	0.000	$0	9,833.7	****
		$0	92.30	0	$0	9,904.9	
	-1	($387,740)	91.79	0	$0	9,979.9	
	-2	($775,480)	91.29	-1	($666,545)	10,020.2	
	-3	($1,163,220)	90.78	-2	($1,333,091)	10,060.5	
	-4	($1,550,960)	90.28	-3	($1,999,636)	10,100.8	
	-5	($1,938,700)	89.78	-4	($2,666,181)	10,141.2	
	-6	($2,326,440)	89.27	-5	($3,332,727)	10,181.5	
	-7	($2,714,180)	88.77	-6	($3,999,272)	10,221.8	
****	-7.758	($3,008,087)	88.39	-7	($4,665,818)	10,262.1	
	-8	($3,101,920)	88.27	-8	($5,332,363)	10,302.4	
	-9	($3,489,660)	87.76	-9	($5,998,908)	10,342.7	
	-10	($3,877,400)	87.26	-10	($6,665,454)	10,383.0	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.91%	12.72%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2018 - December 2018

Unit: Hines 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$252,197	93.25	10	$4,758,674	6,830.2	
	9	$226,977	93.16	9	$4,282,807	6,871.1	
	8	$201,758	93.07	8	$3,806,939	6,912.0	
	7	$176,538	92.99	7	$3,331,072	6,952.8	
	6	$151,318	92.90	6	$2,855,205	6,993.7	
	5	$126,098	92.81	5	$2,379,337	7,034.5	
	4	$100,879	92.72	4	$1,903,470	7,075.4	
	3	$75,659	92.63	3	$1,427,602	7,116.3	
	2	$50,439	92.54	2	$951,735	7,157.1	
	1	$25,220	92.45	1	$475,867	7,198.0	
		$0	92.36	0	$0	7,238.9	
	0	$0	92.36	0.000	$0	7,317.6	****
		$0	92.36	0	$0	7,313.9	
	-1	($52,755)	92.18	0	$0	7,388.9	
	-2	($105,510)	91.99	-1	($475,867)	7,429.7	
	-3	($158,265)	91.80	-2	($951,735)	7,470.6	
	-4	($211,021)	91.62	-3	($1,427,602)	7,511.4	
	-5	($263,776)	91.43	-4	($1,903,470)	7,552.3	
	-6	($316,531)	91.25	-5	($2,379,337)	7,593.2	
	-7	($369,286)	91.06	-6	($2,855,205)	7,634.0	
	-8	($422,041)	90.88	-7	($3,331,072)	7,674.9	
	-9	($474,796)	90.69	-8	($3,806,939)	7,715.8	
****	-9.231	($486,983)	90.65	-9	($4,282,807)	7,756.6	
	-10	($527,551)	90.51	-10	($4,758,674)	7,797.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.48%	9.08%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2018 - December 2018

Unit: Hines 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$5,452,135	80.88	10	$1,948,151	7,006.8	
	10	$5,452,135	80.88	9	$1,753,336	7,034.2	
	9	$4,906,922	79.69	8	$1,558,521	7,061.7	
	8	$4,361,708	78.50	7	$1,363,706	7,089.2	
	7	$3,816,495	77.31	6	$1,168,891	7,116.7	
	6	$3,271,281	76.12	5	$974,075	7,144.1	
	5	$2,726,068	74.93	4	$779,260	7,171.6	
	4	$2,180,854	73.74	3	$584,445	7,199.1	
	3	$1,635,641	72.54	2	$389,630	7,226.6	
	2	$1,090,427	71.35	1	$194,815	7,254.1	
	1	$545,214	70.16	0	$0	7,281.5	
		$0	68.97	0.000	$0	7,375.4	****
	0	$0	68.97	0	$0	7,356.5	
		$0	68.97	0	$0	7,431.5	
	-1	($1,112,693)	66.50	-1	($194,815)	7,459.0	
	-2	($2,225,386)	64.03	-2	($389,630)	7,486.5	
	-3	($3,338,080)	61.56	-3	($584,445)	7,514.0	
	-4	($4,450,773)	59.09	-4	($779,260)	7,541.4	
	-5	($5,563,466)	56.62	-5	($974,075)	7,568.9	
	-6	($6,676,159)	54.15	-6	($1,168,891)	7,596.4	
	-7	($7,788,853)	51.67	-7	($1,363,706)	7,623.9	
	-8	($8,901,546)	49.20	-8	($1,558,521)	7,651.4	
	-9	($10,014,239)	46.73	-9	($1,753,336)	7,678.8	
	-10	($11,126,932)	44.26	-10	($1,948,151)	7,706.3	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
10.41%	3.72%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2018 - December 2018

Unit: Hines 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$515,116	88.43	10	$4,073,706	6,861.3	
	10	$515,116	88.43	9	$3,666,335	6,896.1	
	9	$463,605	88.29	8	$3,258,965	6,930.9	
	8	$412,093	88.15	7	$2,851,594	6,965.7	
	7	$360,581	88.02	6	$2,444,224	7,000.6	
	6	$309,070	87.88	5	$2,036,853	7,035.4	
	5	$257,558	87.74	4	$1,629,482	7,070.2	
	4	$206,046	87.60	3	$1,222,112	7,105.1	
	3	$154,535	87.46	2	$814,741	7,139.9	
	2	$103,023	87.32	1	$407,371	7,174.7	
	1	$51,512	87.18	0	$0	7,209.6	
		$0	87.04	0.000	$0	7,223.8	****
	0	$0	87.04	0	$0	7,284.6	
		$0	87.04	0	$0	7,359.6	
	-1	($87,929)	86.75	-1	($407,371)	7,394.4	
	-2	($175,858)	86.47	-2	($814,741)	7,429.2	
	-3	($263,787)	86.18	-3	($1,222,112)	7,464.0	
	-4	($351,716)	85.89	-4	($1,629,482)	7,498.9	
	-5	($439,645)	85.61	-5	($2,036,853)	7,533.7	
	-6	($527,574)	85.32	-6	($2,444,224)	7,568.5	
	-7	($615,502)	85.03	-7	($2,851,594)	7,603.4	
	-8	($703,431)	84.75	-8	($3,258,965)	7,638.2	
	-9	($791,360)	84.46	-9	($3,666,335)	7,673.0	
	-10	($879,289)	84.18	-10	($4,073,706)	7,707.9	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.98%	7.78%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2018 - December 2018

Unit: Hines 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$2,710,687	87.98	10	$2,679,106	6,786.4	
	10	$2,710,687	87.98	9	$2,411,195	6,806.8	
	9	$2,439,619	87.50	8	$2,143,285	6,827.3	
	8	$2,168,550	87.03	7	$1,875,374	6,847.8	
	7	$1,897,481	86.56	6	$1,607,463	6,868.2	
	6	$1,626,412	86.09	5	$1,339,553	6,888.7	
	5	$1,355,344	85.61	4	$1,071,642	6,909.1	
	4	$1,084,275	85.14	3	$803,732	6,929.6	
	3	$813,206	84.67	2	$535,821	6,950.0	
	2	$542,137	84.19	1.127	$301,935	6,967.9	****
	1	$271,069	83.72	1	$267,911	6,970.5	
		$0	83.25	0	$0	6,990.9	
	0	$0	83.25	0	$0	7,065.9	
		$0	83.25	0	$0	7,140.9	
	-1	($529,185)	82.28	-1	($267,911)	7,161.4	
	-2	($1,058,370)	81.30	-2	($535,821)	7,181.9	
	-3	($1,587,556)	80.33	-3	($803,732)	7,202.3	
	-4	($2,116,741)	79.36	-4	($1,071,642)	7,222.8	
	-5	($2,645,926)	78.38	-5	($1,339,553)	7,243.2	
	-6	($3,175,111)	77.41	-6	($1,607,463)	7,263.7	
	-7	($3,704,297)	76.44	-7	($1,875,374)	7,284.1	
	-8	($4,233,482)	75.46	-8	($2,143,285)	7,304.6	
	-9	($4,762,667)	74.49	-9	($2,411,195)	7,325.0	
	-10	($5,291,852)	73.52	-10	($2,679,106)	7,345.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.17%	5.11%

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Bartow CC	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-Dec Period
1. EAF	100.00	99.71	83.44	99.07	90.94	81.24	80.39	90.71	97.50	100.00	93.43	88.22	91.99
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	723.1	576.0	617.3	699.2	660.7	586.4	601.2	675.8	702.7	708.6	654.3	605.9	7,811.2
4. RSH	20.9	95.7	13.3	14.1	16.0	7.1	7.6	5.2	0.5	35.4	23.9	55.2	294.9
5. UH	0.0	0.3	112.4	6.7	67.4	126.4	135.2	63.0	16.8	0.0	42.7	82.9	653.9
6. POH	0.0	0.0	111.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.8	23.4	162.8
7. FOH	0.0	0.3	0.8	6.7	67.4	126.4	135.2	63.0	6.6	0.0	3.4	41.0	450.8
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.2	0.0	11.6	18.5	40.3
9. PPOH	0.0	0.0	64.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	47.4	0.0	111.5
10. LR PP (MW)	0.0	0.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	67.0	0.0	131.1
11. PFOH	0.0	15.1	0.0	0.0	0.0	229.2	247.9	139.5	19.3	0.0	6.1	75.7	732.7
12. LR PF (MW)	0.0	120.0	0.0	0.0	0.0	40.8	46.4	47.2	67.0	0.0	67.0	67.0	49.1
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.3	0.0	21.3
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	67.0	0.0	67.0
15. NSC (MW)	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
16. OPER MBTU	4,808,629	3,821,765	2,964,776	5,087,891	4,578,391	4,024,793	4,218,831	4,702,160	5,000,877	5,101,315	4,571,596	3,942,161	52,823,185
17. NET GEN (MWH)	627,889	499,274	384,312	670,047	575,313	532,174	548,354	612,491	654,739	674,976	597,846	514,812	6,892,227
18. ANOHR (BTU/KWH)	7,658.4	7,654.6	7,714.5	7,593.3	7,958.1	7,562.9	7,693.6	7,677.1	7,638.0	7,557.8	7,646.8	7,657.5	7,664.2
19. NOF (%)	80.40	80.26	80.30	88.73	80.63	84.03	84.46	83.92	86.27	88.20	84.60	78.68	85.55
20. NPC (MW)	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
ANOHR EQUATION:	ANOHR=	-34.745	x NOF +	10,406.07									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Crystal River 4	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-Dec Period
1. EAF	95.73	99.52	6.43	65.82	81.03	90.51	88.76	99.77	86.97	97.83	65.93	97.43	81.21
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	744.0	672.0	47.8	482.3	615.0	654.3	665.6	744.0	637.7	744.0	236.7	313.8	6,557.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	248.0	414.5	662.5
5. UH	0.0	0.0	695.2	237.7	129.0	65.8	78.5	0.0	82.3	0.0	236.4	15.7	1,540.4
6. POH	0.0	0.0	695.2	211.0	0.0	0.0	0.0	0.0	0.0	0.0	149.0	15.7	1,070.9
7. FOH	0.0	0.0	0.0	24.6	129.0	65.8	78.5	0.0	0.0	0.0	87.4	0.0	385.2
8. MOH	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	82.3	0.0	0.0	0.0	84.3
9. PPOH	0.6	4.0	0.0	0.0	0.0	5.3	4.1	4.3	0.0	111.4	62.9	0.0	192.6
10. LR PP (MW)	555.0	426.0	0.0	0.0	0.0	350.2	93.1	93.0	0.0	100.2	105.5	0.0	116.7
11. PFOH	65.7	6.5	0.0	6.0	39.7	0.0	20.4	8.1	125.7	2.0	0.0	11.7	285.8
12. LR PF (MW)	339.0	93.0	0.0	93.0	106.8	0.0	161.4	99.5	63.1	93.0	0.0	209.9	148.2
13. PMOH	0.0	0.0	0.0	34.1	13.4	0.0	0.0	0.0	3.0	0.5	0.0	0.0	50.9
14. LR PM (MW)	0.0	0.0	0.0	160.0	331.0	0.0	0.0	0.0	93.0	284.0	0.0	0.0	202.1
15. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
16. OPER MBTU	4,015,993	3,240,899	222,277	2,320,777	3,054,194	3,469,320	3,871,499	4,473,772	3,639,986	4,299,907	1,374,567	1,980,857	35,964,047
17. NET GEN (MWH)	413,001	321,886	22,657	218,186	299,484	342,469	391,864	450,913	359,989	440,456	136,228	204,395	3,601,528
18. ANOHR (BTU/KWH)	9,723.9	10,068.5	9,810.5	10,636.7	10,198.2	10,130.3	9,879.7	9,921.6	10,111.4	9,762.4	10,090.2	9,691.3	9,985.8
19. NOF (%)	77.96	67.27	66.60	63.53	68.39	73.52	82.69	85.12	79.29	83.15	80.84	91.48	77.14
20. NPC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
ANOHR EQUATION:	ANOHR=	-27.878	x NOF +	12,341.34									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Crystal River 5	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-Dec Period
1. EAF	97.92	97.07	97.93	49.56	79.30	99.11	38.70	99.53	100.00	97.60	95.88	83.29	86.24
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	744.0	668.0	730.3	368.4	627.7	718.3	293.5	744.0	720.0	744.0	700.1	636.3	7,694.5
4. 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
5. UH	0.0	4.0	12.7	351.6	116.3	1.8	450.5	0.0	0.0	0.0	21.0	107.7	1,065.5
6. POH	0.0	0.0	0.0	351.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	351.6
7. FOH	0.0	0.0	12.7	0.0	116.3	0.0	450.5	0.0	0.0	0.0	21.0	0.0	600.4
8. MOH	0.0	4.0	0.0	0.0	0.0	1.8	0.0	0.0	0.0	0.0	0.0	107.7	113.5
9. PPOH	2.0	0.0	0.0	90.1	279.5	9.9	0.0	12.9	0.0	124.7	16.8	1.3	537.0
10. LR PP (MW)	91.0	0.0	0.0	91.0	90.5	91.0	0.0	156.9	0.0	101.6	91.0	388.0	95.5
11. PFOH	36.5	0.0	5.0	0.0	3.0	2.8	16.8	1.5	0.0	0.0	19.5	59.4	144.4
12. LR PF (MW)	296.0	0.0	377.0	0.0	496.0	90.8	236.2	53.0	0.0	0.0	240.5	187.8	237.5
13. PMOH	0.0	22.5	0.0	0.0	0.0	23.8	0.0	4.5	0.0	0.0	0.0	1.8	52.7
14. LR PM (MW)	0.0	496.0	0.0	0.0	0.0	91.0	0.0	90.9	0.0	0.0	0.0	91.2	264.0
15. NSC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
16. OPER MBTU	4,144,476	3,158,789	3,800,740	1,868,760	2,793,588	3,835,936	1,665,160	3,991,755	3,924,950	3,924,692	3,962,015	3,354,162	40,425,021
17. NET GEN (MWH)	429,919	314,067	386,624	173,240	262,152	378,749	162,511	406,473	390,915	394,687	389,819	344,040	4,033,196
18. ANOHR (BTU/KWH)	9,640.1	10,057.7	9,830.6	10,787.1	10,656.4	10,127.9	10,246.4	9,820.5	10,040.4	9,943.8	10,163.7	9,749.3	10,023.1
19. NOF (%)	81.39	66.22	74.56	66.23	58.82	74.27	77.98	76.95	76.47	74.72	78.43	76.15	73.83
20. NPC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
ANOHR EQUATION:	ANOHR=	-29.847	x NOF +	12,297.79									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 1	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-Dec Period
1. EAF	98.04	99.99	48.88	68.76	96.33	95.08	97.93	95.56	99.77	88.59	94.98	92.93	89.66
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	714.5	672.0	363.7	495.0	704.7	685.2	732.3	715.1	720.0	580.8	621.7	61.6	7,066.6
4. RSH	16.7	0.0	0.1	0.0	16.0	0.0	0.0	2.8	0.0	78.3	63.1	632.4	809.3
5. UH	12.9	0.0	379.3	224.9	23.3	34.8	11.7	26.2	0.0	84.9	36.2	49.9	884.1
6. POH	0.0	0.0	359.9	224.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	584.8
7. FOH	12.9	0.0	19.4	0.0	10.8	34.8	0.0	7.4	0.0	3.5	36.2	0.0	124.9
8. MOH	0.0	0.0	0.0	0.0	12.5	0.0	11.7	18.8	0.0	81.4	0.0	49.9	174.4
9. PPOH	0.0	0.8	0.0	0.0	6.0	0.0	19.3	25.5	12.1	0.0	0.0	0.0	63.6
10. LR PP (MW)	0.0	50.6	0.0	0.0	77.9	0.0	66.7	79.2	66.2	0.0	0.0	0.0	72.5
11. PFOH	12.4	0.0	3.6	0.0	10.4	4.3	10.9	22.5	0.0	0.0	0.0	18.1	82.2
12. LR PF (MW)	69.8	0.0	76.6	0.0	67.6	69.1	51.6	61.4	0.0	0.0	0.0	73.6	65.9
13. PMOH	0.0	0.0	0.0	0.0	11.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.9
14. LR PM (MW)	0.0	0.0	0.0	0.0	67.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	67.6
15. NSC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
16. OPER MBTU	2,318,447	2,219,815	1,223,092	1,644,308	2,242,655	2,321,872	2,490,175	2,347,965	2,433,049	1,834,526	1,852,459	152,454	23,080,816
17. NET GEN (MWH)	321,975	304,049	166,322	225,245	306,258	314,667	339,141	320,728	332,410	250,688	254,813	19,132	3,155,428
18. ANOHR (BTU/KWH)	7,200.7	7,300.8	7,353.8	7,300.1	7,322.8	7,378.8	7,342.6	7,320.7	7,319.4	7,318.0	7,269.9	7,968.5	7,314.6
19. NOF (%)	91.04	91.40	92.39	91.92	87.80	92.78	93.56	90.61	93.27	87.20	82.80	62.71	90.21
20. NPC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
ANOHR EQUATION:	ANOHR=	-3.146	x NOF +	7,594.62									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 2	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-Dec Period
1. EAF	100.00	99.39	90.43	43.47	94.38	99.97	99.66	99.42	100.00	100.00	96.46	97.28	93.42
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	693.3	464.5	669.7	313.0	703.7	720.0	742.2	741.0	720.0	712.9	625.3	285.0	7,390.7
4. RSH	50.7	204.0	2.2	0.0	0.6	0.0	0.0	0.0	0.0	31.1	73.6	438.8	801.1
5. UH	0.0	3.5	71.1	407.0	39.7	0.0	1.8	3.0	0.0	0.0	22.1	20.1	568.2
6. POH	0.0	0.0	0.0	407.0	33.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	440.7
7. FOH	0.0	3.5	71.1	0.0	6.0	0.0	1.8	0.0	0.0	0.0	0.0	20.1	102.5
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	22.1	0.0	25.1
9. PPOH	0.0	0.0	0.0	0.0	8.5	1.8	3.9	7.8	0.0	0.0	0.0	1.0	22.8
10. LR PP (MW)	0.0	0.0	0.0	0.0	63.9	65.4	58.9	57.7	0.0	0.0	0.0	61.7	61.0
11. PFOH	0.0	3.4	0.0	0.0	6.2	0.0	1.8	0.0	0.0	0.0	0.0	0.0	11.4
12. LR PF (MW)	0.0	92.3	0.0	0.0	91.0	0.0	86.2	0.0	0.0	0.0	0.0	0.0	90.6
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	0.0	0.0	22.8	0.0	25.7
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.4	0.0	0.0	80.3	0.0	81.9
15. NSC (MW)	527	527	527	527	527	527	527	527	527	527	527	527	527
16. OPER MBTU	2,282,848	1,421,231	2,365,022	1,097,825	2,362,778	2,544,480	2,712,733	2,660,024	2,585,795	2,491,923	1,927,826	862,539	25,315,023
17. NET GEN (MWH)	314,763	201,941	323,728	148,433	318,884	340,617	364,250	362,461	348,781	341,025	259,988	114,555	3,439,426
18. ANOHR (BTU/KWH)	7,252.6	7,037.9	7,305.6	7,396.1	7,409.5	7,470.2	7,447.4	7,338.8	7,413.8	7,307.2	7,415.1	7,529.5	7,360.2
19. NOF (%)	86.15	82.49	91.73	89.99	85.98	89.77	93.12	92.81	91.92	90.77	78.90	76.26	88.31
20. NPC (MW)	527	527	527	527	527	527	527	527	527	527	527	527	527
ANOHR EQUATION:	ANOHR=	-4.024	x NOF +	7,696.67									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Jan-Dec

Hines 3	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Period
1. EAF	99.51	99.62	98.60	97.89	96.11	99.90	97.99	99.11	93.49	5.24	99.80	100.00	90.45
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	478.3	413.2	598.2	705.8	710.6	720.0	732.0	739.5	673.5	39.0	606.0	706.7	7,122.7
4. RSH	262.5	256.5	135.9	1.4	11.6	0.0	0.0	0.0	0.0	0.0	113.6	37.3	818.7
5. UH	3.2	2.3	9.0	12.8	21.9	0.0	12.1	4.5	46.5	705.0	1.4	0.0	818.6
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.5	704.8	1.4	0.0	752.7
7. FOH	3.2	2.3	0.8	0.0	0.0	0.0	0.0	4.5	0.0	0.2	0.0	0.0	11.0
8. MOH	0.0	0.0	8.1	12.8	21.9	0.0	12.1	0.0	0.0	0.0	0.0	0.0	54.9
9. PPOH	0.0	1.0	0.0	5.0	8.4	8.0	10.7	14.5	6.2	0.0	0.0	0.0	53.8
10. LR PP (MW)	0.0	59.1	0.0	41.8	42.1	47.8	45.3	48.6	30.6	0.0	0.0	0.0	44.3
11. PFOH	2.9	1.1	1.0	0.0	39.4	0.0	0.0	4.4	0.0	0.0	0.0	0.0	48.8
12. LR PF (MW)	81.0	81.0	81.3	0.0	64.7	0.0	0.0	86.0	0.0	0.0	0.0	0.0	68.3
13. PMOH	0.0	0.0	7.9	12.5	9.1	0.0	11.8	0.0	0.0	0.0	0.0	0.0	41.3
14. LR PM (MW)	0.0	0.0	83.0	81.7	84.0	0.0	87.0	0.0	0.0	0.0	0.0	0.0	83.9
15. NSC (MW)	521	521	521	521	521	521	521	521	521	521	521	521	521
16. OPER MBTU	1,547,605	1,321,596	1,931,761	2,329,506	2,328,108	2,402,780	2,486,811	2,579,596	2,340,526	101,869	1,932,659	2,310,749	23,613,567
17. NET GEN (MWH)	207,822	179,431	273,608	325,098	327,585	341,385	354,820	357,834	326,866	12,658	269,105	313,285	3,289,497
18. ANOHR (BTU/KWH)	7,446.8	7,365.5	7,060.3	7,165.6	7,106.9	7,038.3	7,008.7	7,208.9	7,160.5	8,047.8	7,181.8	7,375.9	7,178.5
19. NOF (%)	83.40	83.34	87.79	88.41	88.49	91.01	93.04	92.88	93.15	62.28	85.24	85.09	88.64
20. NPC (MW)	521	521	521	521	521	521	521	521	521	521	521	521	521
ANOHR EQUATION:	ANOHR=	-9.438	x NOF +	8,075.83									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 4	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-Dec Period
1. EAF	98.03	99.97	99.99	97.21	99.74	99.51	98.46	96.04	99.99	100.00	45.50	68.65	91.92
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	574.2	630.0	743.0	697.7	744.0	719.0	734.9	715.3	720.0	640.2	0.0	436.6	7,355.0
4. RSH	156.8	42.0	0.0	4.8	0.0	0.0	0.0	5.4	0.0	103.8	328.0	76.7	717.5
5. UH	13.0	0.0	0.0	17.5	0.0	1.0	9.1	23.3	0.0	0.0	393.0	230.7	687.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	393.0	194.5	587.4
7. FOH	13.0	0.0	0.0	0.0	0.0	1.0	5.0	22.3	0.0	0.0	0.0	36.2	77.5
8. MOH	0.0	0.0	0.0	17.5	0.0	0.0	4.1	1.0	0.0	0.0	0.0	0.0	22.6
9. PPOH	0.5	2.1	1.0	0.0	16.1	21.0	10.3	20.9	1.0	0.0	0.0	0.0	72.8
10. LR PP (MW)	50.1	50.9	47.7	0.0	58.1	55.8	54.5	54.4	45.7	0.0	0.0	0.0	55.3
11. PFOH	12.0	0.0	0.0	0.0	0.6	1.0	4.7	57.3	0.0	0.0	0.0	19.4	95.0
12. LR PF (MW)	69.2	0.0	0.0	0.0	54.3	76.2	71.1	34.8	0.0	0.0	0.0	67.2	48.1
13. PMOH	0.0	0.0	0.0	16.5	0.0	0.0	3.8	0.0	0.0	0.0	0.0	0.0	20.4
14. LR PM (MW)	0.0	0.0	0.0	78.1	0.0	0.0	79.1	0.0	0.0	0.0	0.0	0.0	78.3
15. NSC (MW)	504	504	504	504	504	504	504	504	504	504	504	504	504
16. OPER MBTU	1,859,462	1,997,841	2,490,044	2,248,954	2,465,014	2,421,836	2,497,460	2,367,658	2,446,225	2,157,252	0	1,279,382	24,231,126
17. NET GEN (MWH)	268,522	289,609	367,086	320,318	349,474	344,155	354,748	336,121	353,302	313,343	0	187,156	3,483,834
18. ANOHR (BTU/KWH)	6,924.8	6,898.4	6,783.3	7,021.0	7,053.5	7,037.1	7,040.1	7,044.1	6,923.9	6,884.6	0.0	6,835.9	6,955.3
19. NOF (%)	92.78	91.21	98.03	91.09	93.20	94.98	95.77	93.24	97.36	97.12	0.00	85.05	93.98
20. NPC (MW)	504	504	504	504	504	504	504	504	504	504	504	504	504
ANOHR EQUATION:	ANOHR=	-4.435	x NOF +	7,470.17									

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PLANNED OUTAGE SCHEDULES
ACTUAL

Duke Energy Florida
January 2018 - December 2018

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow CC	03/10 (0055) - 03/28 (0828)	Gas Turbine - Boroscope Inspection; Circulating Water Chemistry
Bartow CC	11/16 (0511) - 11/22 (1209)	Gas Turbine - Boroscope Inspection
Bartow CC	12/02 (2323) - 12/8 (1721)	Gas Turbine - Boroscope Inspection
Crystal River 4	03/02 (2347) - 04/09 (1902)	Minor Boiler Overhaul (less than 720 Hours)
Crystal River 4	11/24 (1901) - 12/01 (1541)	Main Transformer
Crystal River 5	04/12 (1417) - 04/27 (0553)	Boiler; Miscellaneous
Hines 1	03/17 (0007) - 04/10 (1106)	General Gas Turbine Unit Inspection
Hines 2	04/14 (0017) - 05/03 (0235)	General Gas Turbine Unit Inspection
Hines 3	09/29 (0054) - 11/01 (0828)	General Gas Turbine Unit Inspection
Hines 4	11/10 (0000) - 12/09 (1400)	General Gas Turbine Unit Inspection

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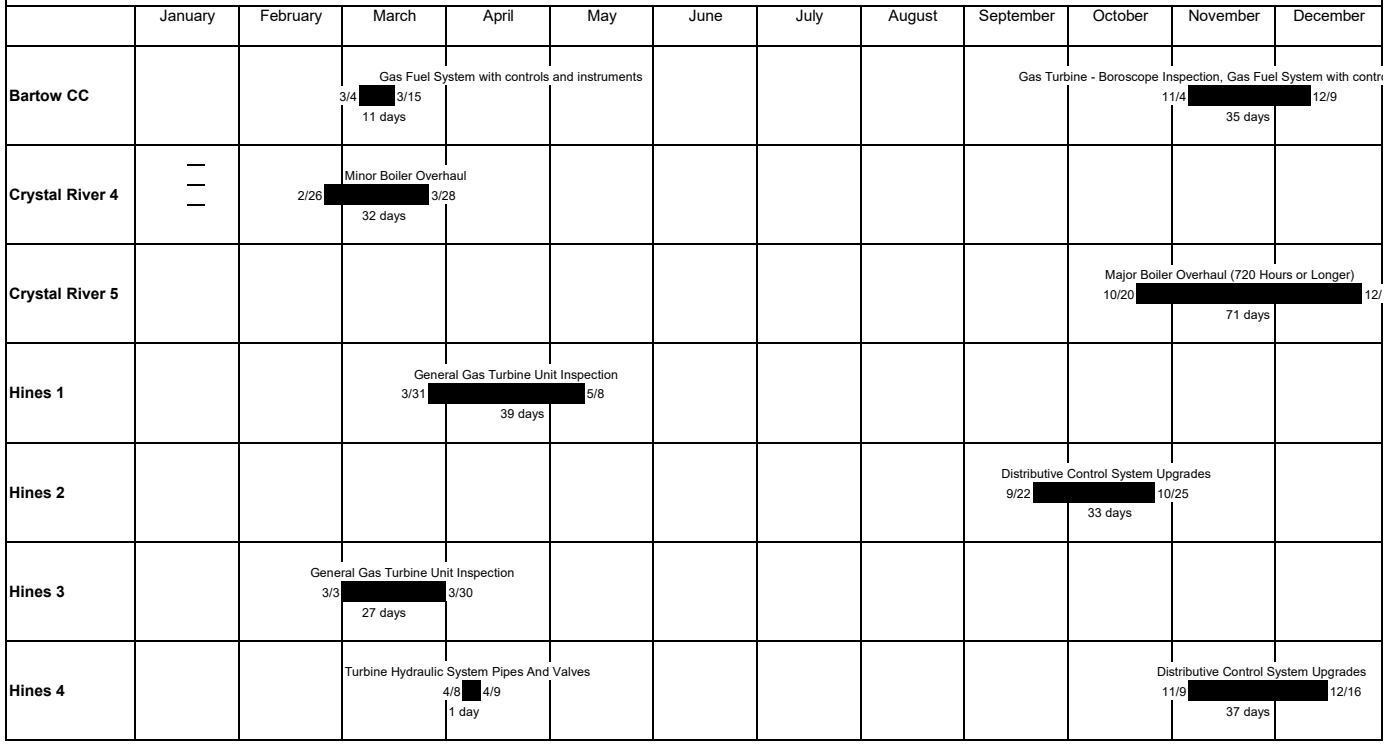
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Planned Outage Schedule - Actual

Duke Energy Florida

January 2018 - December 2018



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GPIF Targets and Ranges for January through December 2020

STANDARD FORM GPIF SCHEDULES

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PARTY: DUKE ENERGY FLORIDA – (DIRECT)
DESCRIPTION: James B. Daniel JBD-1P

Original Sheet No. 7.101.1

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Duke Energy Florida
Period of: January 2020 - December 2020

Generating Performance Incentive Points (GPIF)	Fuel Saving/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	$4,386,758	$2,193,379
1	$2,193,379	$1,096,690
0	$0	$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

ESTIMATED

Duke Energy Florida
Period of: January 2020 - December 2020

1	Beginning of period balance of common equity	$6,766,769,536	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2020	$6,815,814,938	
3	Month of FEBRUARY 2020	$6,856,540,263	
4	Month of MARCH 2020	$6,895,985,159	
5	Month of APRIL 2020	$6,937,015,976	
6	Month of MAY 2020	$7,001,233,688	
7	Month of JUNE 2020	$7,086,227,133	
8	Month of JULY 2020	$7,174,605,589	
9	Month of AUGUST 2020	$7,262,739,039	
10	Month of SEPTEMBER 2020	$7,345,718,380	
11	Month of OCTOBER 2020	$7,408,423,923	
12	Month of NOVEMBER 2020	$7,450,545,975	
13	Month of DECEMBER 2020	$7,503,390,729	
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$7,115,770,025	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	73.1092%	
17	Maximum allowed incentive dollars (LINE 14 times LINE 15 divided by LINE 16)	$24,332,676	
18	Jurisdictional Sales	39,496,577	MWH
19	Total Sales	39,670,279	MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	99.56%	
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	$24,225,613	
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 7.101.1	$10,966,895	
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	$10,966,895	

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GPIF TARGET AND RANGE SUMMARY

Duke Energy Florida
Period of: January 2020 - December 2020

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Bartow 4	7.37	88.20	92.74	79.17	1,617	(2,661)
Hines 1	0.73	87.02	89.01	82.98	160	(785)
Hines 2	0.11	90.32	91.15	88.60	25	(447)
Hines 3	0.72	93.73	94.89	91.35	159	(726)
Hines 4	3.95	83.95	87.02	77.60	866	(2,199)
Osprey 1	2.38	88.14	91.02	82.23	521	(1,136)
GPIF System	15.26				3,348	(7,954)

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (BTU/KWH)	ANOHR RANGE Max. (BTU/KWH)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Bartow 4	30.88	7,892	72.9	7,496	8,289	6,774	(6,774)
Hines 1	12.12	7,261	88.0	6,922	7,600	2,659	(2,659)
Hines 2	8.83	7,410	83.9	7,159	7,660	1,937	(1,937)
Hines 3	9.52	7,266	80.5	7,019	7,514	2,089	(2,089)
Hines 4	7.34	6,982	91.7	6,801	7,162	1,611	(1,611)
Osprey 1	16.03	7,291	58.6	6,717	7,866	3,517	(3,517)
GPIF System	84.74					18,586	(18,586)

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

Duke Energy Florida
Period of: January 2020 - December 2020

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jan-Jun 2019 POF	Actual Performance 1st Prior Period Jan-Jun 2019 EUOF	Actual Performance 1st Prior Period Jan-Jun 2019 EUOR	Actual Performance 2nd Prior Period Jan-Dec 2018 POF	Actual Performance 2nd Prior Period Jan-Dec 2018 EUOF	Actual Performance 2nd Prior Period Jan-Dec 2018 EUOR
Bartow 4	7.37	48.30	2.05	9.75	9.75	1.63	8.03	8.70	1.86	6.00	6.33
Hines 1	0.73	4.77	8.74	4.24	5.08	9.02	11.92	14.93	6.68	3.56	4.23
Hines 2	0.11	0.74	7.92	1.76	2.20	0.00	0.27	0.34	5.03	1.52	1.78
Hines 3	0.72	4.74	3.83	2.44	2.67	0.00	0.80	0.95	8.59	0.90	1.10
Hines 4	3.95	25.88	9.56	6.48	7.37	0.00	0.10	0.11	6.71	1.28	1.51
Osprey 1	2.38	15.57	5.74	6.12	7.50	19.87	1.99	4.26	12.08	5.25	8.97
GPIF System Wghtd. Avg.	15.26	100.00	5.01	7.67	8.17	4.31	4.83	5.65	5.28	4.27	5.11

Plant/Unit	Actual Performance 3rd Prior Period Jan-Dec 2017 POF	Actual Performance 3rd Prior Period Jan-Dec 2017 EUOF	Actual Performance 3rd Prior Period Jan-Dec 2017 EUOR	Actual Performance 4th Prior Period Jan-Dec 2016 POF	Actual Performance 4th Prior Period Jan-Dec 2016 EUOF	Actual Performance 4th Prior Period Jan-Dec 2016 EUOR	Actual Performance 5th Prior Period Jan-Dec 2015 POF	Actual Performance 5th Prior Period Jan-Dec 2015 EUOF	Actual Performance 5th Prior Period Jan-Dec 2015 EUOR
Bartow 4	1.43	10.97	11.43	10.34	8.02	9.11	8.21	3.89	4.33
Hines 1	7.71	3.08	3.57	10.11	1.78	2.02	15.13	1.29	1.55
Hines 2	7.93	0.61	0.74	8.73	3.81	4.43	0.00	45.82	46.11
Hines 3	7.71	3.08	3.57	10.11	1.78	2.02	15.13	1.29	1.55
Hines 4	7.93	0.61	0.74	8.73	3.81	4.43	0.00	45.82	46.11
Osprey 1	31.86	3.30	6.63	11.30	1.21	1.61			
GPIF System Wghtd. Avg.	8.50	6.27	7.09	10.04	5.24	6.02	5.41	14.20	14.51

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

Duke Energy Florida
Period of: January 2020 - December 2020

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan 2018 - Dec 2018	2nd Prior HR Jan 2017 - Dec 2017	3rd Prior HR Jan 2016 - Dec 2016
Bartow 4	30.88	36.45	7,892	7,907	8,003	7,910
Hines 1	12.12	14.31	7,261	7,369	7,253	7,139
Hines 2	8.83	10.42	7,410	7,397	7,436	7,352
Hines 3	9.52	11.24	7,266	7,339	7,189	7,281
Hines 4	7.34	8.67	6,982	6,961	7,013	7,015
Osprey 1	16.03	18.92	7,291	7,401	7,137	7,303
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
GPIF System Weighted Avg.	84.74	100.00	7,489	7,535	7,496	7,231

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DERIVATION OF WEIGHTING FACTORS

Duke Energy Florida
Period of: January 2020 - December 2020

Unit Performance Indicator	Production Costing Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Bartow 4 EAF	1,795,013	1,793,396	1,617	7.37
Bartow 4 HR	1,795,013	1,788,239	6,774	30.88
Hines 1 EAF	1,795,013	1,794,853	160	0.73
Hines 1 HR	1,795,013	1,792,354	2,659	12.12
Hines 2 EAF	1,795,013	1,794,988	25	0.11
Hines 2 HR	1,795,013	1,793,076	1,937	8.83
Hines 3 EAF	1,795,013	1,794,854	159	0.72
Hines 3 HR	1,795,013	1,792,924	2,089	9.52
Hines 4 EAF	1,795,013	1,794,146	866	3.95
Hines 4 HR	1,795,013	1,793,402	1,611	7.34
Osprey 1 EAF	1,795,013	1,794,491	521	2.38
Osprey 1 HR	1,795,013	1,791,496	3,517	16.03

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 2020 - December 2020

Bartow 4

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
9	$1,455,421	92.29	9	$6,096,319	7,527.8
8	$1,293,707	91.83	8	$5,418,950	7,559.9
7	$1,131,994	91.38	7	$4,741,581	7,592.1
6	$970,280	90.93	6	$4,064,213	7,624.2
5	$808,567	90.47	5	$3,386,844	7,656.4
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
					7,817.1
0	$0	88.20	0	$0	7,892.1
					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:	Heat Rate Weighting Factor:
8.41%	35.24%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida

Period of: January 2020 - December 2020

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
					7,185.9
0	$0	87.02	0	$0	7,260.9
					7,335.9
-1	($78,466)	86.62	-1	($265,911)	7,362.3
-2	($156,933)	86.21	-2	($531,822)	7,388.7
-3	($235,399)	85.81	-3	($797,734)	7,415.1
-4	($313,865)	85.40	-4	($1,063,645)	7,441.5
-5	($392,331)	85.00	-5	($1,329,556)	7,467.9
-6	($470,798)	84.60	-6	($1,595,467)	7,494.3
-7	($549,264)	84.19	-7	($1,861,378)	7,520.7
-8	($627,730)	83.79	-8	($2,127,289)	7,547.1
-9	($706,196)	83.38	-9	($2,393,201)	7,573.5
-10	($784,663)	82.98	-10	($2,659,112)	7,600.0

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.83%	13.83%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida

Period of: January 2020 - December 2020

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
					7,334.6
0	$0	90.32	0	$0	7,409.6
					7,484.6
-1	($44,740)	90.15	-1	($193,697)	7,502.2
-2	($89,481)	89.98	-2	($387,393)	7,519.7
-3	($134,221)	89.80	-3	($581,090)	7,537.2
-4	($178,962)	89.63	-4	($774,786)	7,554.8
-5	($223,702)	89.46	-5	($968,483)	7,572.3
-6	($268,442)	89.29	-6	($1,162,179)	7,589.9
-7	($313,183)	89.12	-7	($1,355,876)	7,607.4
-8	($357,923)	88.95	-8	($1,549,572)	7,625.0
-9	($402,664)	88.77	-9	($1,743,269)	7,642.5
-10	($447,404)	88.60	-10	($1,936,965)	7,660.0

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.13%	10.08%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida

Period of: January 2020 - December 2020

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
					7,191.2
0	$0	93.73	0	$0	7,266.2
					7,341.2
-1	($72,598)	93.50	-1	($208,857)	7,358.4
-2	($145,197)	93.26	-2	($417,714)	7,375.7
-3	($217,795)	93.02	-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:	Heat Rate Weighting Factor:
0.83%	10.86%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida

Period of: January 2020 - December 2020

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	$779,709	86.71	9	$1,449,708	6,811.7
8	$693,075	86.40	8	$1,288,630	6,822.2
7	$606,441	86.10	7	$1,127,551	6,832.8
6	$519,806	85.79	6	$966,472	6,843.3
5	$433,172	85.49	5	$805,393	6,853.8
4	$346,537	85.18	4	$644,315	6,864.4
3	$259,903	84.87	3	$483,236	6,874.9
2	$173,269	84.57	2	$322,157	6,885.5
1	$86,634	84.26	1	$161,079	6,896.0
					6,906.5
0	$0	83.95	0	$0	6,981.5
					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:	Heat Rate Weighting Factor:
4.51%	8.38%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida

Period of: January 2020 - December 2020

Osprey 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$521,293	91.02	10	$806,829	7,395.6
9	$469,164	90.73	9	$726,146	7,401.7
8	$417,035	90.45	8	$645,463	7,407.8
7	$364,905	90.16	7	$564,781	7,413.9
6	$312,776	89.87	6	$484,098	7,420.1
5	$260,647	89.58	5	$403,415	7,426.2
4	$208,517	89.29	4	$322,732	7,432.3
3	$156,388	89.01	3	$242,049	7,438.4
2	$104,259	88.72	2	$161,366	7,444.5
1	$52,129	88.43	1	$80,683	7,450.7
					7,456.8
0	$0	88.14	0	$0	7,531.8
					7,606.8
-1	($113,638)	87.55	-1	($80,683)	7,612.9
-2	($227,276)	86.96	-2	($161,366)	7,619.0
-3	($340,915)	86.37	-3	($242,049)	7,625.1
-4	($454,553)	85.78	-4	($322,732)	7,631.3
-5	($568,191)	85.19	-5	($403,415)	7,637.4
-6	($681,829)	84.60	-6	($484,098)	7,643.5
-7	($795,467)	84.01	-7	($564,781)	7,649.6
-8	($909,106)	83.42	-8	($645,463)	7,655.7
-9	($1,022,744)	82.82	-9	($726,146)	7,661.9
-10	($1,136,382)	82.23	-10	($806,829)	7,668.0

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.71%	4.20%

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UNIT PERFORMANCE DATA

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2020 - December 2020

PLANT/UNIT **Bartow 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	90.25	88.53	67.67	90.25	90.25	90 25	90 25	90.25	90.25	90.25	90.25	90 25	88.20
2. POF	0.00	1.72	22.58	0 00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0 00	2.05
3. EUOF	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75
4. EUOR	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	680.4	636.5	680.4	658.4	680.4	658.4	680.4	680.4	658.4	680.4	658.4	680.4	8,033 0
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	63.6	59.5	63 6	61.6	63 6	61.6	63.6	63 6	61.6	63.6	61 6	63.6	751 0
9. POH & PPOH	0.0	12.0	168 0	0.0	0 0	0.0	0.0	0 0	0.0	0.0	0 0	0.0	180 0
10. FOH & PFOH	56.5	52.8	56 5	54.7	56 5	54.7	56.5	56 5	54.7	56.5	54.7	56.5	666 8
11. MOH & PMOH	16.0	15.0	16 0	15.5	16 0	15.5	16.0	16 0	15.5	16.0	15 5	16.0	189.4
12. Oper. Btu(MBtu)	3,980,826	3,847,133	3,723,091	4,311,035	4,508,787	4,590,602	4,893,574	4,749,778	4,491,544	4,994,748	4,473,240	4,170,027	52,856,548
13. Net Gen. (MWH)	490,456 0	477,400.0	452,520 0	545,531.0	572,392 0	591,236.0	636,340.0	611,974 0	574,804.0	653,847.0	571,797 0	519,126.0	6,697,423 0
14. ANOHR (Btu/KWH)	8,117	8,059	8,227	7,902	7,877	7,764	7,690	7,761	7,814	7,639	7,823	8,033	7,892
15. NOF (%)	63.0	65.5	58.1	72.4	73 5	78.5	81.7	78 6	76.3	84.0	75 9	66.7	72 9
16. NSC (MW)	1144	1144	1144	1144	1144	1144	1144	1144	1144	1144	1144	1144	1144
17. ANOHR Equation	ANOHR=	-22.758 x NOF +		9,550.1									

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2020 - December 2020

PLANT/UNIT **Hines 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.45	96.26	95.19	9.55	79.85	94 97	94 98	94.98	94.98	95.57	94.99	95 36	87.02
2. POF	0.00	0.00	0.00	90.00	16.13	0.00	0 00	0.00	0.00	0.00	0.00	0 00	8.74
3. EUOF	3.55	3.74	4.81	0.45	4.02	5.03	5 02	5.02	5.02	4.43	5.01	4 64	4.24
4. EUOR	5.08	5.08	5.08	5 08	5.08	5.08	5 08	5.08	5.08	5.08	5.08	5 08	5.08
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	496 8	489.5	672.4	61.5	562 2	679.6	701.7	701 2	678.8	618 9	678.1	648.7	6,989.4
7. RSH	223.4	183.0	39.4	7.6	34 8	7.8	8.6	9 2	8.6	95.4	9.4	64.2	691.4
8. UH	23.8	23.5	32 2	650.9	147 0	32.6	33.7	33 6	32.6	29.7	32 5	31.1	1103 2
9. POH & PPOH	0.0	0.0	0 0	648.0	120 0	0.0	0.0	0 0	0.0	0.0	0 0	0.0	768 0
10. FOH & PFOH	11.0	10.8	14 8	1.4	12.4	15.0	15.5	15 5	15.0	13.7	15 0	14.3	154 2
11. MOH & PMOH	15.5	15.3	21 0	1.9	17 5	21.2	21.9	21 9	21.2	19.3	21.1	20.2	217 9
12. Oper. Btu(MBtu)	1,459,041	1,482,416	2,115,274	189,575	1,630,845	2,082,508	2,181,885	2,152,032	2,103,899	1,996,610	2,318,368	2,148,805	21,874,926
13. Net Gen. (MWH)	198,106 0	202,623.0	291,685 0	26,021.0	220,856 0	285,406.0	300,033.0	295,042 0	289,092.0	277,017.0	326,651 0	300,168.0	3,012,700 0
14. ANOHR (Btu/KWH)	7,365	7,316	7,252	7,285	7,384	7,297	7,272	7,294	7,278	7,208	7,097	7,159	7,261
15. NOF (%)	81.4	84.5	88 5	86.4	80 2	85.7	87.3	85 9	86.9	91.3	98 3	94.4	88 0
16. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
17. ANOHR Equation	ANOHR=	-15.806 x NOF +		8,651.3									

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2020 - December 2020

PLANT/UNIT **Hines 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	98.77	97.04	23.70	81.60	97.92	97 81	97 80	97.84	97.81	97.89	97.98	98 55	90.32
2. POF	0.00	1.72	75.81	16.67	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0 00	7.92
3. EUOF	1.23	1.24	0.49	1.73	2.08	2.19	2 20	2.16	2.19	2.11	2.02	1.45	1.76
4. EUOR	2.20	2.20	2.20	2 20	2.20	2.20	2 20	2.20	2.20	2.20	2.20	2 20	2.20
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	407 6	382.3	162 8	554.2	688.4	699.6	726.2	713.1	701.5	696 3	645.1	480.1	6,857 3
7. RSH	328 0	305.8	193 8	34.4	41.4	6.0	2.8	16 2	4.0	33.4	61 6	254.0	1281.4
8. UH	8.4	7.9	387.4	131.4	14 2	14.4	15.0	14.7	14.5	14.3	13 3	9.9	645 3
9. POH & PPOH	0.0	12.0	564 0	120.0	0 0	0.0	0.0	0 0	0.0	0.0	0 0	0.0	696 0
10. FOH & PFOH	5.6	5.2	2 2	7.6	9.4	9.6	9.9	9 8	9.6	9.5	8 8	6.6	93 8
11. MOH & PMOH	3.6	3.4	1.4	4.9	6.1	6.2	6.4	6 3	6.2	6.1	5.7	4.2	60.4
12. Oper. Btu(MBtu)	1,152,290	1,141,717	325,184	1,753,057	2,148,775	2,342,603	2,495,097	2,424,863	2,380,826	2,444,793	2,199,009	1,496,270	22,325,972
13. Net Gen. (MWH)	152,953 0	152,471.0	41,896 0	235,729.0	288,465 0	317,333.0	339,184.0	329,165 0	323,099.0	333,377 0	298,607.0	200,831.0	3,013,110 0
14. ANOHR (Btu/KWH)	7,534	7,488	7,762	7,437	7,449	7,382	7,356	7,367	7,369	7,333	7,364	7,450	7,410
15. NOF (%)	71.6	76.1	49.1	81.2	80 0	86.6	89.1	88.1	87.9	91.4	88 3	79.8	83 9
16. NSC (MW)	524	524	524	524	524	524	524	524	524	524	524	524	524
17. ANOHR Equation	ANOHR=	-10.130 x NOF +		8,259.0									

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EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2020 - December 2020

PLANT/UNIT **Hines 3**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	97.98	97.67	97.43	97.36	97.35	97 35	97 34	97.33	97.38	53.43	97.36	97 56	93.73
2. POF	0.00	0.00	0.00	0 00	0.00	0.00	0 00	0.00	0.00	45.16	0.00	0 00	3.83
3. EUOF	2.02	2.33	2.57	2 64	2.65	2.65	2 66	2.67	2.62	1.41	2.64	2.44	2.44
4. EUOR	2.67	2.67	2.67	2 67	2.67	2.67	2 67	2.67	2.67	2.67	2.67	2 67	2.67
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	549 2	593.3	699 3	695.8	721 3	698.1	724.1	725 0	690.3	382 9	695.0	664.3	7,838.7
7. RSH	181 2	88.0	27.4	7.0	4 8	4.6	2.0	1 0	12.6	15.6	7 8	63.2	415 2
8. UH	13.6	14.7	17 3	17.2	17 9	17.3	17.9	18 0	17.1	345 5	17 2	16.5	530.1
9. POH & PPOH	0.0	0.0	0 0	0.0	0 0	0.0	0.0	0 0	0.0	336.0	0 0	0.0	336 0
10. FOH & PFOH	10.6	11.5	13 5	13.4	13 9	13.5	14.0	14 0	13.3	7.4	13.4	12.8	151 5
11. MOH & PMOH	4.4	4.8	5 6	5.6	5 8	5.6	5.8	5 8	5.5	3.1	5 6	5.3	62 9
12. Oper. Btu(MBtu)	1,641,548	1,708,287	2,060,407	1,940,795	2,077,944	2,093,380	2,322,984	2,270,881	2,126,437	1,200,669	2,219,040	1,943,983	23,621,229
13. Net Gen. (MWH)	225,441 0	232,438.0	281,938 0	262,131.0	282,769 0	287,732.0	325,314.0	315,819 0	294,372.0	167,034.0	310,320 0	265,550.0	3,250,858 0
14. ANOHR (Btu/KWH)	7,281	7,349	7,308	7,404	7,349	7,275	7,141	7,190	7,224	7,188	7,151	7,321	7,266
15. NOF (%)	79.7	76.1	78 3	73.2	76.1	80.0	87.2	84 6	82.8	84.7	86.7	77.6	80 5
16. NSC (MW)	515	515	515	515	515	515	515	515	515	515	515	515	515
17. ANOHR Equation	ANOHR=	-18.685 x NOF +		8,770.8									

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.107.1

EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2020 - December 2020

PLANT/UNIT **Hines 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	92.77	92.76	93.06	92.68	92.79	92 69	93 02	92.81	92.85	89.87	0.00	80 85	83.95
2. POF	0.00	0.00	0.00	0 00	0.00	0.00	0 00	0.00	0.00	3.23	100.00	12 90	9.56
3. EUOF	7.23	7.24	6.94	7 32	7.21	7.31	6 98	7.19	7.15	6.90	0.00	6 24	6.48
4. EUOR	7.37	7.37	7.37	7 37	7.37	7.37	7 37	7.37	7.37	7.37	0.00	7 37	7.37
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	677 8	635.1	650.7	663.7	675.4	663.2	654.2	674 3	648.5	646 8	0 0	585.3	7,175.1
7. RSH	14.0	12.0	43 2	5.2	16 6	5.8	39.4	17 8	21.6	23.4	0 0	17.6	216 6
8. UH	52.2	48.9	50.1	51.1	52 0	51.0	50.4	51 9	49.9	73.8	720 0	141.1	1392 3
9. POH & PPOH	0.0	0.0	0 0	0.0	0 0	0.0	0.0	0 0	0.0	24.0	720 0	96.0	840 0
10. FOH & PFOH	50.3	47.2	48 3	49.3	50 2	49.3	48.6	50.1	48.2	48.0	0 0	43.5	532 9
11. MOH & PMOH	3.5	3.2	3 3	3.4	3.4	3.4	3.3	3.4	3.3	3.3	0 0	3.0	36 6
12. Oper. Btu(MBtu)	2,237,112	2,092,843	2,154,302	2,195,697	2,162,555	2,228,297	2,149,476	2,197,987	2,110,617	2,191,789	-	1,984,570	23,705,845
13. Net Gen. (MWH)	320,404 0	299,701.0	308,626 0	314,536.0	308,937 0	319,638.0	307,733.0	314,468 0	301,929.0	314,635.0	-	284,902.0	3,395,509 0
14. ANOHR (Btu/KWH)	6,982	6,983	6,980	6,981	7,000	6,971	6,985	6,990	6,990	6,966	-	6,966	6,982
15. NOF (%)	91.6	91.5	91 9	91.8	88 6	93.4	91.2	90.4	90.2	94.3	0 0	94.3	91.7
16. NSC (MW)	516	516	516	516	516	516	516	516	516	516	516	516	516
17. ANOHR Equation	ANOHR=	-6.017 x NOF +		7,533.3									

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.107.1

EST MATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2020 - December 2020

PLANT/UNIT **Osprey 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	92.68	92.66	39.47	84.14	93.50	93 37	93.13	93.34	93.23	93.56	93.69	95 61	88.14
2. POF	0.00	0.00	58.06	10.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0 00	5.74
3. EUOF	7.32	7.34	2.46	5 86	6.50	6.63	6 87	6.66	6.77	6.44	6.31	4 39	6.12
4. EUOR	7.50	7.50	7.50	7 50	7.50	7.50	7 50	7.50	7.50	7.50	7.50	7 50	7.50
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	671 6	630.5	226.1	520.8	596 6	588.9	630.7	611 6	601.1	590.7	560.4	402.6	6,631.4
7. RSH	18.0	14.4	67 6	85.0	99 0	83.4	62.2	82 8	70.2	105.4	114.2	308.8	1111 0
8. UH	54.4	51.1	450 3	114.2	48.4	47.7	51.1	49 6	48.7	47.9	45.4	32.6	1041 6
9. POH & PPOH	0.0	0.0	432 0	72.0	0 0	0.0	0.0	0 0	0.0	0.0	0 0	0.0	504 0
10. FOH & PFOH	7.6	7.1	2 6	5.9	6 8	6.7	7.1	6 9	6.8	6.7	6.4	4.6	75 2
11. MOH & PMOH	46.8	44.0	15 8	36.3	41 6	41.1	44.0	42.7	41.9	41.2	39.1	28.1	462 5
12. Oper. Btu(MBtu)	1,511,893	1,424,681	551,196	1,334,818	1,574,771	1,567,505	1,823,059	1,665,519	1,664,375	1,632,851	1,396,545	872,957	17,036,276
13. Net Gen. (MWH)	198,027 0	186,669.0	72,769 0	177,179.0	209,731 0	208,971.0	245,556.0	222,643 0	222,948.0	218,678.0	184,802 0	113,946.0	2,261,919 0
14. ANOHR (Btu/KWH)	7,635	7,632	7,575	7,534	7,509	7,501	7,424	7,481	7,465	7,467	7,557	7,661	7,532
15. NOF (%)	50.7	50.9	55 3	58.5	60.4	61.0	66.9	62 5	63.7	63.6	56.7	48.6	58 6
16. NSC (MW)	582	582	582	582	582	582	582	582	582	582	582	582	582
17. ANOHR Equation	ANOHR=	-12.972 x NOF +		8,292.0									

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

PLANNED OUTAGE SCHEDULES

Duke Energy Florida
Period of: January 2020 - December 2020

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow 4	02/29 (0001) - 03/07 (2400)	2x0 first 8 days, 2x1 for balance, STM condenser cleaning, L-0 inspection, replace F91 delam valves, boroscopes A&C, B&D
Bartow 4	03/08 (0001) - 03/14 (2400)	2x0 first 8 days, 2x1 for balance, STM condenser cleaning, L-0 inspection, replace F91 delam valves, boroscopes A&C, B&D
Hines 1	04/04 (0001) - 04/24 (2400)	Full block BOP, ST-V
Hines 2	02/29 (0001) - 03/20 (2400)	BOP, ST-2 Gen MEDIUM robotic (per Fischli), ST-V, L-0 inspection
Hines 2	03/16 (0001) - 04/05 (2400)	Full block BOP last 21, CT MI/Rotor EOL (A&B),Gen Minor (A&B), BOP, ST-2 Gen MEDIUM (per Fischli), ST-V
Hines 3	10/03 (0001) - 10/16 (2400)	BOP, L-0 inspection
Hines 4	10/31 (0001) - 12/04 (2400)	BOP,Gen. Minor (B,ST), ST-V, Controls Upgrade
Osprey 1	03/14 (0001) - 04/03 (2400)	BOP

AVERAGE NET OPERATING HEAT RATE CURVES

DUKE ENERGY FLORIDA

Bartow Unit 4

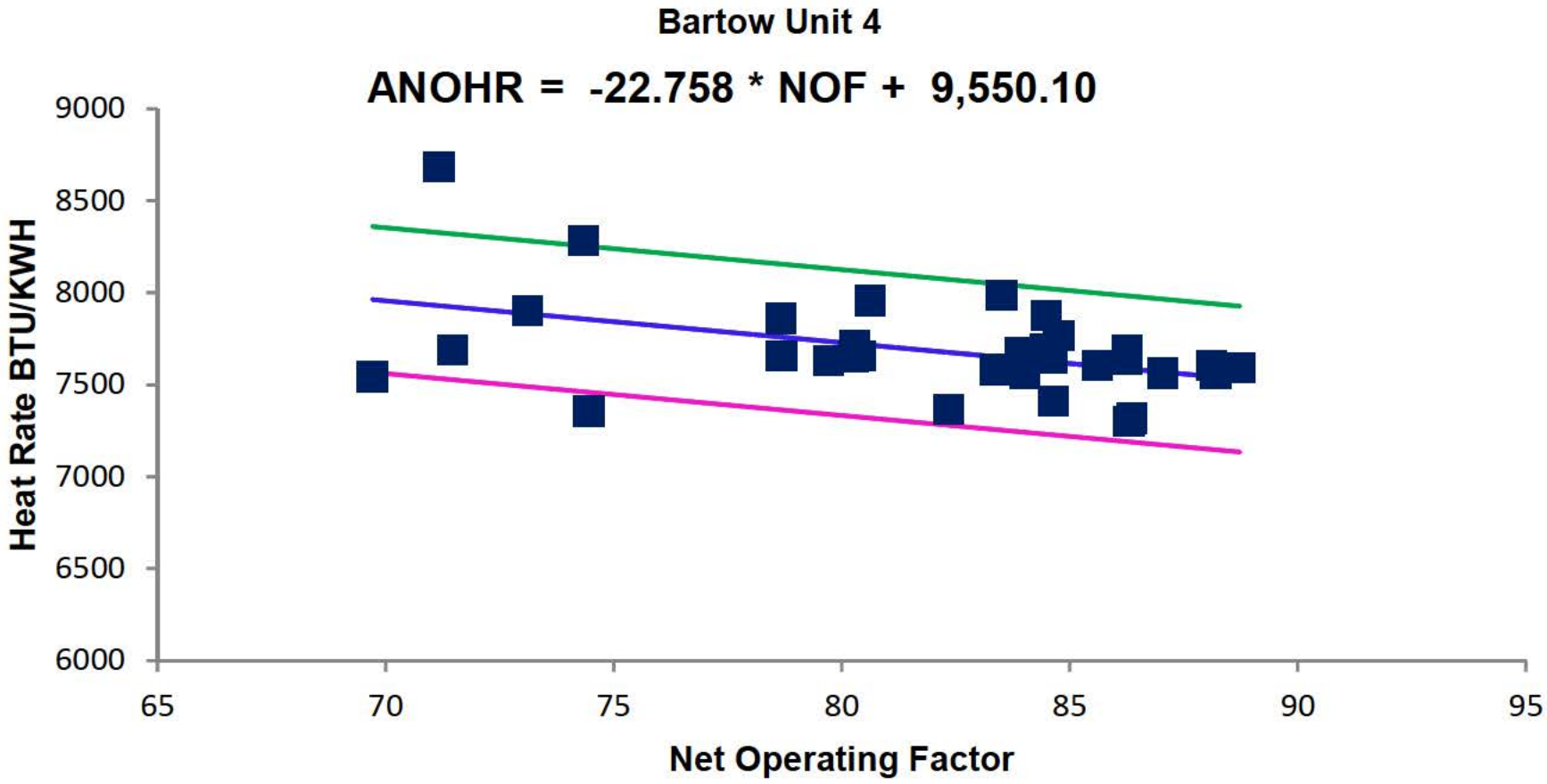
ANOHR = -22.758 * NOF + 9,550.10

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-16	86.3	7,303	7,586	-283.3	396.4
Aug-16	86.4	7,319	7,585	-265.6	396.4
Sep-16	84.7	7,414	7,624	-210.1	396.4
Oct-16	71.2	8,686	7,930	755.5	396.4
Dec-16	74.5	7,357	7,855	-498.2	396.4
Jan-17	82.4	7,367	7,676	-309.1	396.4
Apr-17	74.3	8,284	7,858	425.6	396.4
May-17	85.6	7,607	7,602	5.6	396.4
Jun-17	87.0	7,565	7,569	-4.2	396.4
Jul-17	86.3	7,685	7,587	98.4	396.4
Aug-17	88.1	7,604	7,545	59.5	396.4
Sep-17	84.5	7,877	7,627	249.7	396.4
Oct-17	84.8	7,767	7,621	146.2	396.4
Nov-17	78.7	7,862	7,760	102.1	396.4
Dec-17	83.5	7,990	7,650	340.4	396.4
Jan-18	80.4	7,658	7,720	-61.9	396.4
Feb-18	80.3	7,655	7,724	-68.9	396.4
Mar-18	80.3	7,715	7,723	-8.1	396.4
Apr-18	88.7	7,593	7,531	62.6	396.4
May-18	80.6	7,958	7,715	243.0	396.4
Jun-18	84.0	7,563	7,638	-74.8	396.4
Jul-18	84.5	7,694	7,628	65.7	396.4
Aug-18	83.9	7,677	7,640	36.9	396.4
Sep-18	86.3	7,638	7,587	51.2	396.4
Oct-18	88.2	7,558	7,543	14.9	396.4
Nov-18	84.6	7,647	7,625	22.0	396.4
Dec-18	78.7	7,657	7,759	-102.0	396.4
Jan-19	79.7	7,632	7,736	-103.7	396.4
Feb-19	71.5	7,689	7,924	-234.4	396.4
Mar-19	69.7	7,545	7,963	-418.5	396.4
Apr-19	73.1	7,902	7,886	16.2	396.4
May-19	83.4	7,583	7,653	-69.9	396.4
Jun-19	84.0	7,655	7,638	17.2	396.4

Regression Output:

Constant	9550.10
Std Err of Y Est	244.7313907
R Squared	0.199487137
No. of Observations	33
Degrees of Freedom	31
X Coefficient	-22.75821475
Std Err of Coef.	8.188117255


Bartow Unit 4
ANOHR = -22.758 * NOF + 9,550.10
Heat Rate BTU/KWH
9000
8500
8000
7500
7000
6500
6000
65
70
75
80
85
90
95
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 1

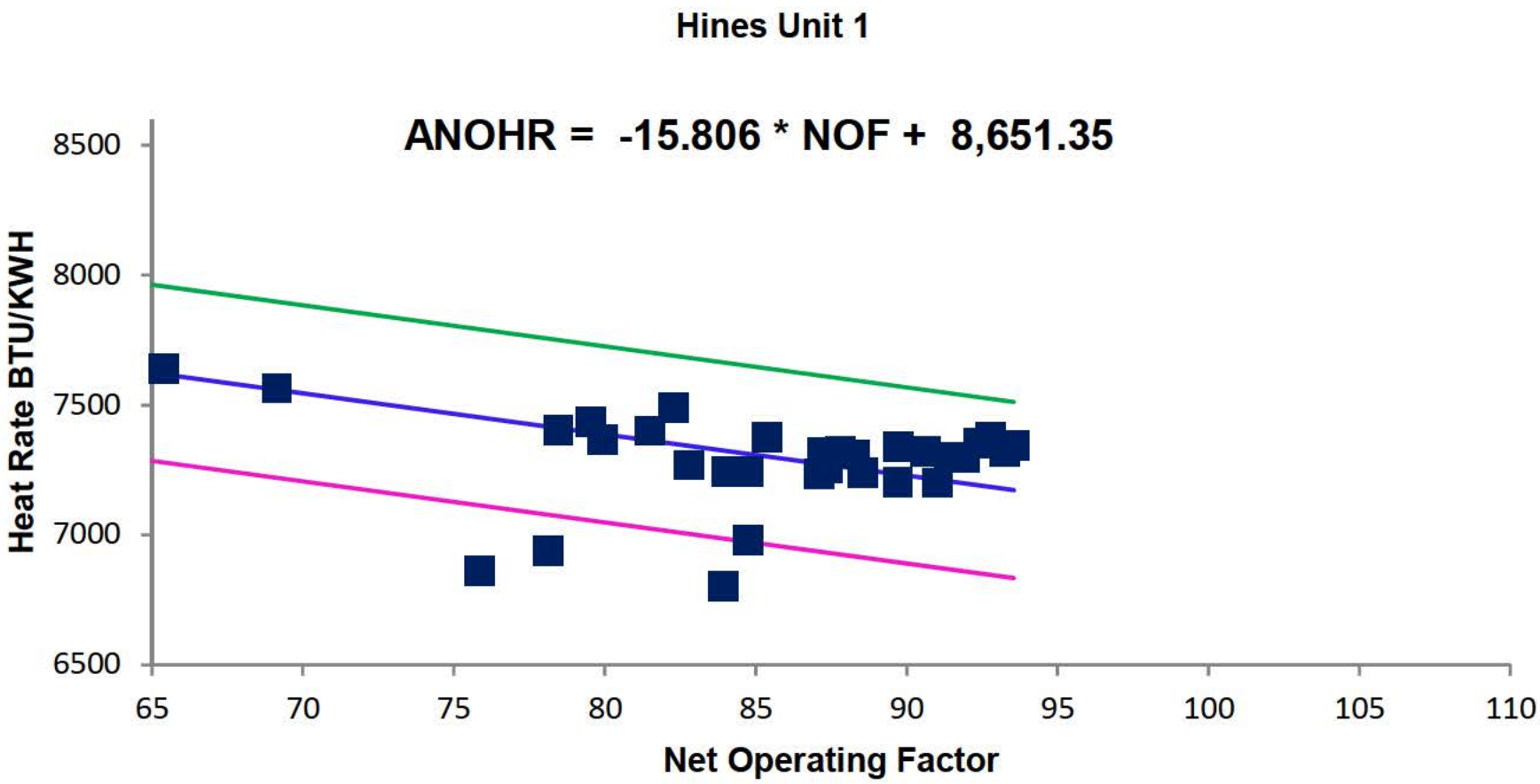
ANOHR = -15.806 * NOF + 8,651.35

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-16	84.1	7,243	7,323	-79.5	339.0
Aug-16	87.1	7,236	7,275	-38.5	339.0
Sep-16	84.8	7,244	7,312	-67.6	339.0
Oct-16	83.9	6,803	7,325	-521.6	339.0
Nov-16	84.7	6,980	7,312	-332.0	339.0
Dec-16	78.1	6,938	7,416	-477.9	339.0
Jan-17	75.8	6,861	7,453	-592.1	339.0
Feb-17	87.4	7,256	7,270	-14.0	339.0
Mar-17	89.7	7,204	7,233	-29.6	339.0
May-17	59.7	8,071	7,708	362.3	339.0
Jun-17	79.9	7,368	7,388	-19.6	339.0
Jul-17	85.4	7,377	7,302	75.1	339.0
Aug-17	88.3	7,310	7,256	54.5	339.0
Sep-17	88.6	7,240	7,251	-11.3	339.0
Oct-17	89.7	7,338	7,233	105.1	339.0
Dec-17	78.5	7,403	7,411	-8.4	339.0
Jan-18	91.0	7,201	7,212	-11.6	339.0
Feb-18	91.4	7,301	7,207	94.2	339.0
Mar-18	92.4	7,354	7,191	162.8	339.0
Apr-18	91.9	7,300	7,198	101.7	339.0
May-18	87.8	7,323	7,264	59.2	339.0
Jun-18	92.8	7,379	7,185	194.0	339.0
Jul-18	93.6	7,343	7,173	170.1	339.0
Aug-18	90.6	7,321	7,219	101.6	339.0
Sep-18	93.3	7,319	7,177	142.3	339.0
Oct-18	87.2	7,318	7,273	44.9	339.0
Nov-18	82.8	7,270	7,343	-72.7	339.0
Dec-18	62.7	7,969	7,660	308.4	339.0
Jan-19	65.4	7,642	7,618	24.6	339.0
Feb-19	81.5	7,401	7,363	38.3	339.0
Mar-19	79.6	7,437	7,394	42.7	339.0
Apr-19	69.1	7,566	7,559	7.0	339.0
May-19	82.3	7,489	7,351	138.1	339.0
Jun-19	81.0	7,420	7,371	49.3	339.0

Regression Output:

Constant	8651.35
Std Err of Y Est	209.206493
R Squared	0.307098717
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-15.80641591
Std Err of Coef.	4.197155864


Hines Unit 1
ANOHR = -15.806 * NOF + 8,651.35
Heat Rate BTU/KWH
8500
8000
7500
7000
6500
65
70
75
80
85
90
95
100
105
110
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 2

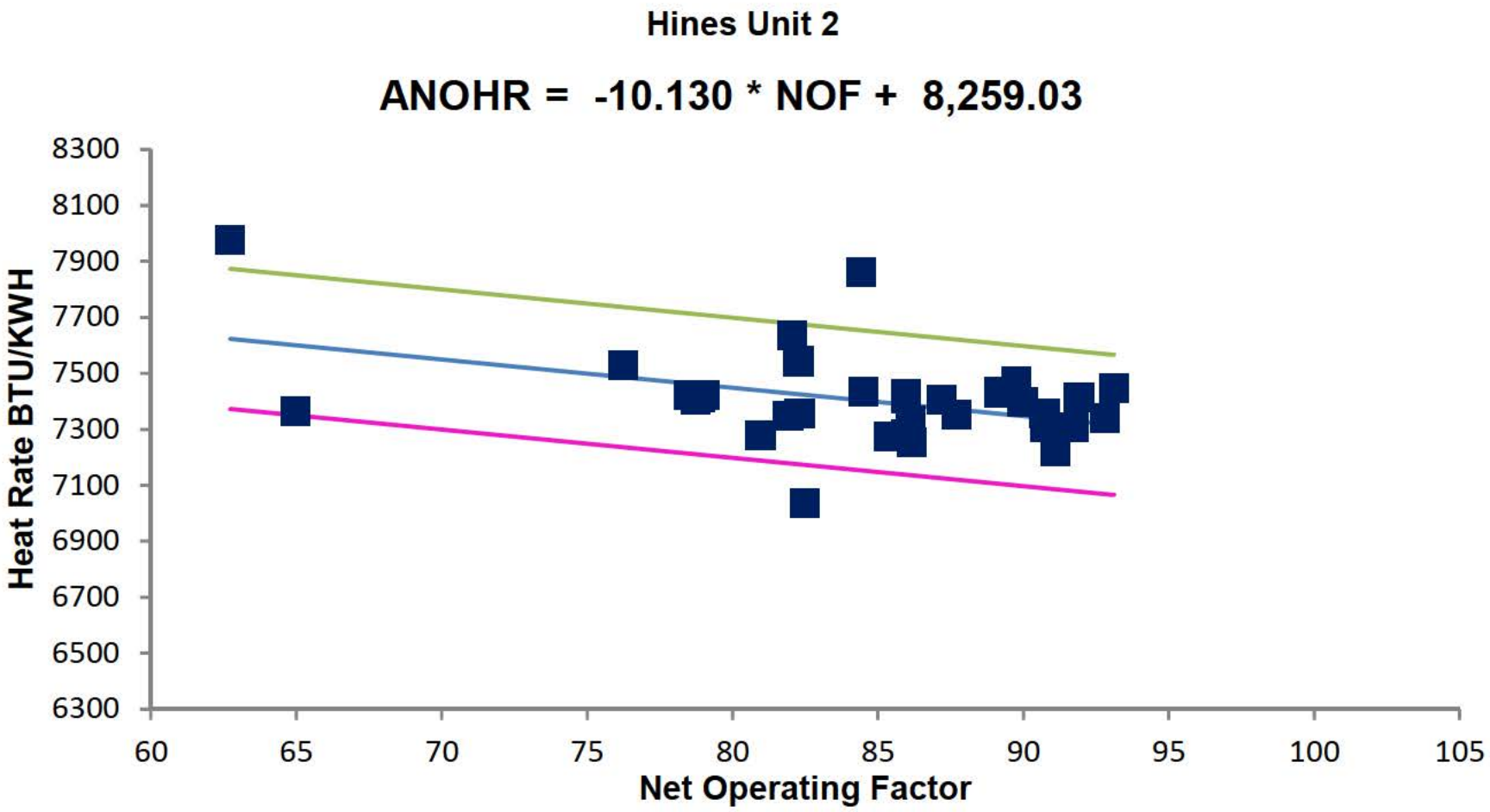
ANOHR = -10.130 * NOF + 8,259.03

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-16	85.4	7,274	7,394	-120.0	250.4
Aug-16	87.7	7,353	7,371	-17.2	250.4
Sep-16	84.4	7,861	7,404	457.1	250.4
Oct-16	86.1	7,299	7,386	-87.5	250.4
Nov-16	79.1	7,422	7,458	-36.7	250.4
Dec-16	65.0	7,365	7,601	-236.0	250.4
Jan-17	78.7	7,408	7,462	-53.7	250.4
Feb-17	78.5	7,421	7,464	-43.1	250.4
Mar-17	91.1	7,222	7,336	-114.2	250.4
Apr-17	82.3	7,543	7,426	117.5	250.4
May-17	81.9	7,350	7,429	-79.3	250.4
Jun-17	84.5	7,436	7,403	32.6	250.4
Jul-17	87.2	7,407	7,376	31.3	250.4
Aug-17	86.0	7,283	7,388	-105.3	250.4
Sep-17	82.1	7,636	7,428	208.1	250.4
Oct-17	62.7	7,978	7,624	354.9	250.4
Dec-17	86.1	7,332	7,387	-54.9	250.4
Jan-18	86.2	7,253	7,386	-133.8	250.4
Feb-18	82.5	7,038	7,423	-385.6	250.4
Mar-18	91.7	7,306	7,330	-24.3	250.4
Apr-18	90.0	7,396	7,347	48.6	250.4
May-18	86.0	7,410	7,388	21.4	250.4
Jun-18	89.8	7,470	7,350	120.5	250.4
Jul-18	93.1	7,447	7,316	131.7	250.4
Aug-18	92.8	7,339	7,319	19.9	250.4
Sep-18	91.9	7,414	7,328	85.9	250.4
Oct-18	90.8	7,307	7,340	-32.4	250.4
Nov-18	78.9	7,415	7,460	-44.8	250.4
Dec-18	76.3	7,529	7,487	42.9	250.4
Jan-19	81.0	7,279	7,439	-160.1	250.4
Feb-19	82.3	7,354	7,425	-71.1	250.4
Apr-19	90.7	7,356	7,340	15.7	250.4
May-19	89.2	7,432	7,356	75.6	250.4
Jun-19	86.0	7,425	7,388	36.2	250.4

Regression Output:

Constant	8259.03
Std Err of Y Est	154.5240897
R Squared	0.174632428
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-10.12957971
Std Err of Coef.	3.892939838


Hines Unit 2
ANOHR = -10.130 * NOF + 8,259.03
Heat Rate BTU/KWH
8300
8100
7900
7700
7500
7300
7100
6900
6700
6500
6300
60
65
70
75
80
85
90
95
100
105
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 3

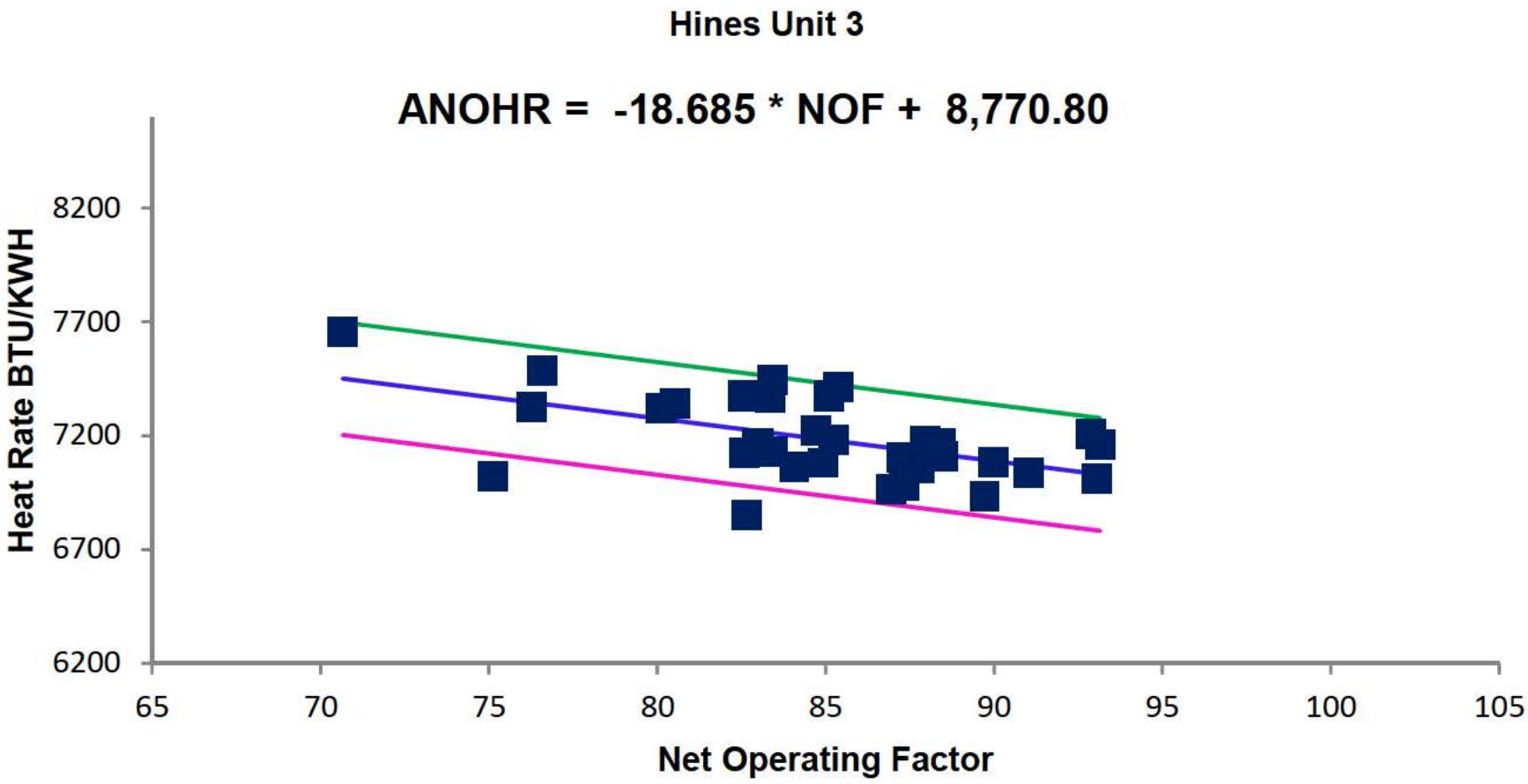
ANOHR = -18.685 * NOF + 8,770.80

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-16	84.7	7,225	7,188	36.8	247.5
Aug-16	87.0	6,966	7,146	-180.3	247.5
Sep-16	82.7	6,850	7,226	-375.7	247.5
Oct-16	76.6	7,485	7,340	145.0	247.5
Nov-16	70.7	7,656	7,451	205.8	247.5
Dec-16	80.1	7,320	7,274	46.0	247.5
Jan-17	82.6	7,376	7,228	147.6	247.5
Feb-17	82.6	7,124	7,228	-103.8	247.5
Apr-17	84.9	7,080	7,184	-103.9	247.5
May-17	80.5	7,342	7,266	75.7	247.5
Jun-17	83.4	7,132	7,212	-79.9	247.5
Jul-17	87.3	7,106	7,140	-34.6	247.5
Aug-17	90.0	7,082	7,090	-7.4	247.5
Sep-17	75.1	7,020	7,367	-346.9	247.5
Oct-17	89.7	6,934	7,094	-160.5	247.5
Dec-17	87.3	6,978	7,139	-161.0	247.5
Jan-18	83.4	7,447	7,212	234.3	247.5
Feb-18	83.3	7,365	7,214	151.9	247.5
Mar-18	87.8	7,060	7,130	-70.1	247.5
Apr-18	88.4	7,166	7,119	46.7	247.5
May-18	88.5	7,107	7,117	-10.5	247.5
Jun-18	91.0	7,038	7,070	-32.0	247.5
Jul-18	93.0	7,009	7,032	-23.7	247.5
Aug-18	92.9	7,209	7,035	173.6	247.5
Sep-18	93.2	7,161	7,030	130.2	247.5
Nov-18	85.2	7,182	7,178	3.7	247.5
Dec-18	85.1	7,376	7,181	195.0	247.5
Jan-19	85.4	7,416	7,175	240.7	247.5
Feb-19	76.3	7,325	7,346	-20.6	247.5
Mar-19	83.0	7,169	7,220	-51.6	247.5
Apr-19	84.1	7,063	7,200	-137.1	247.5
May-19	88.0	7,180	7,127	52.8	247.5
Jun-19	84.3	7,211	7,197	13.9	247.5

Regression Output:

Constant	8770.80
Std Err of Y Est	152.8110874
R Squared	0.29197747
No. of Observations	33
Degrees of Freedom	31
X Coefficient	-18.68475877
Std Err of Coef.	5.225832874


Hines Unit 3
ANOHR = -18.685 * NOF + 8,770.80
Heat Rate BTU/KWH
8200
7700
7200
6700
6200
65
70
75
80
85
90
95
100
105
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 4

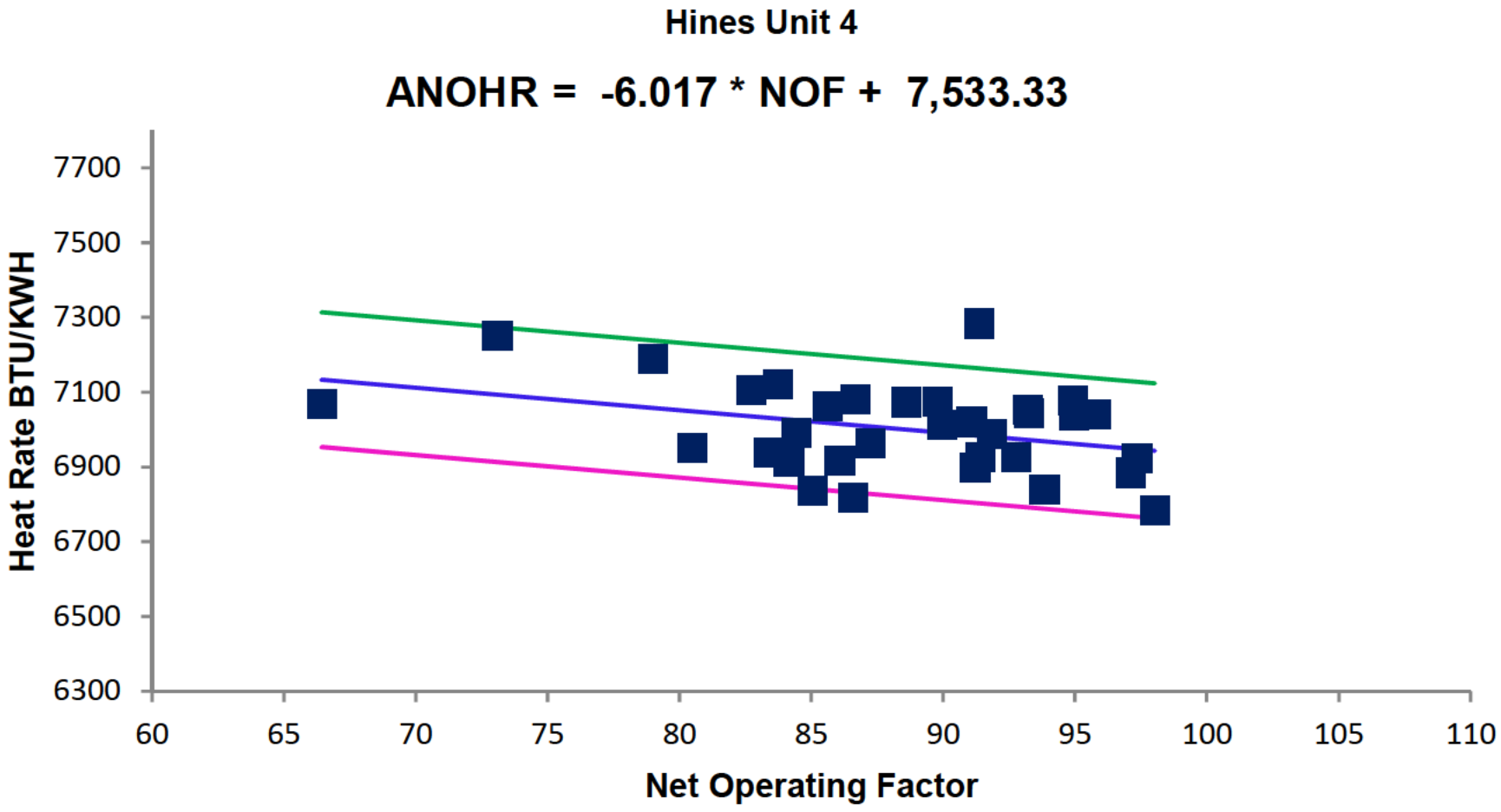
ANOHR = -6.017 * NOF + 7,533.33

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Aug-16	83.7	7,122	7,029	92.6	180.4
Sep-16	86.1	6,915	7,015	-100.2	180.4
Oct-16	73.1	7,250	7,094	156.6	180.4
Nov-16	66.4	7,068	7,134	-66.1	180.4
Dec-16	79.0	7,189	7,058	130.9	180.4
Jan-17	91.4	7,283	6,984	299.8	180.4
Feb-17	90.0	7,013	6,992	21.1	180.4
Mar-17	93.9	6,840	6,969	-128.4	180.4
Apr-17	88.6	7,074	7,000	73.4	180.4
May-17	80.5	6,951	7,049	-98.6	180.4
Jun-17	84.4	6,993	7,025	-32.4	180.4
Jul-17	82.8	7,105	7,035	69.4	180.4
Aug-17	86.7	7,079	7,012	67.4	180.4
Sep-17	91.9	6,986	6,981	5.8	180.4
Oct-17	94.9	7,077	6,962	115.1	180.4
Dec-17	87.2	6,964	7,009	-44.1	180.4
Jan-18	92.8	6,925	6,975	-50.3	180.4
Feb-18	91.2	6,898	6,985	-86.1	180.4
Mar-18	98.0	6,783	6,944	-160.2	180.4
Apr-18	91.1	7,021	6,985	35.7	180.4
May-18	93.2	7,053	6,973	80.9	180.4
Jun-18	95.0	7,037	6,962	75.2	180.4
Jul-18	95.8	7,040	6,957	83.0	180.4
Aug-18	93.2	7,044	6,972	71.7	180.4
Sep-18	97.4	6,924	6,948	-23.7	180.4
Oct-18	97.1	6,885	6,949	-64.4	180.4
Dec-18	85.1	6,836	7,022	-185.7	180.4
Jan-19	91.4	6,925	6,983	-58.3	180.4
Feb-19	84.2	6,913	7,027	-113.9	180.4
Mar-19	83.4	6,937	7,032	-94.6	180.4
Apr-19	86.6	6,817	7,012	-195.4	180.4
May-19	89.8	7,075	6,993	81.5	180.4
Jun-19	85.6	7,061	7,018	42.4	180.4

Regression Output:

Constant	7533.33
Std Err of Y Est	111.3559717
R Squared	0.127056003
No. of Observations	33
Degrees of Freedom	31
X Coefficient	-6.01661338
Std Err of Coef.	2.832480021


Hines Unit 4
ANOHR = -6.017 * NOF + 7,533.33
Heat Rate BTU/KWH
7700
7500
7300
7100
6900
6700
6500
6300
60
65
70
75
80
85
90
95
100
105
110
Net Operating Factor

DUKE ENERGY FLORIDA

Osprey Unit 1

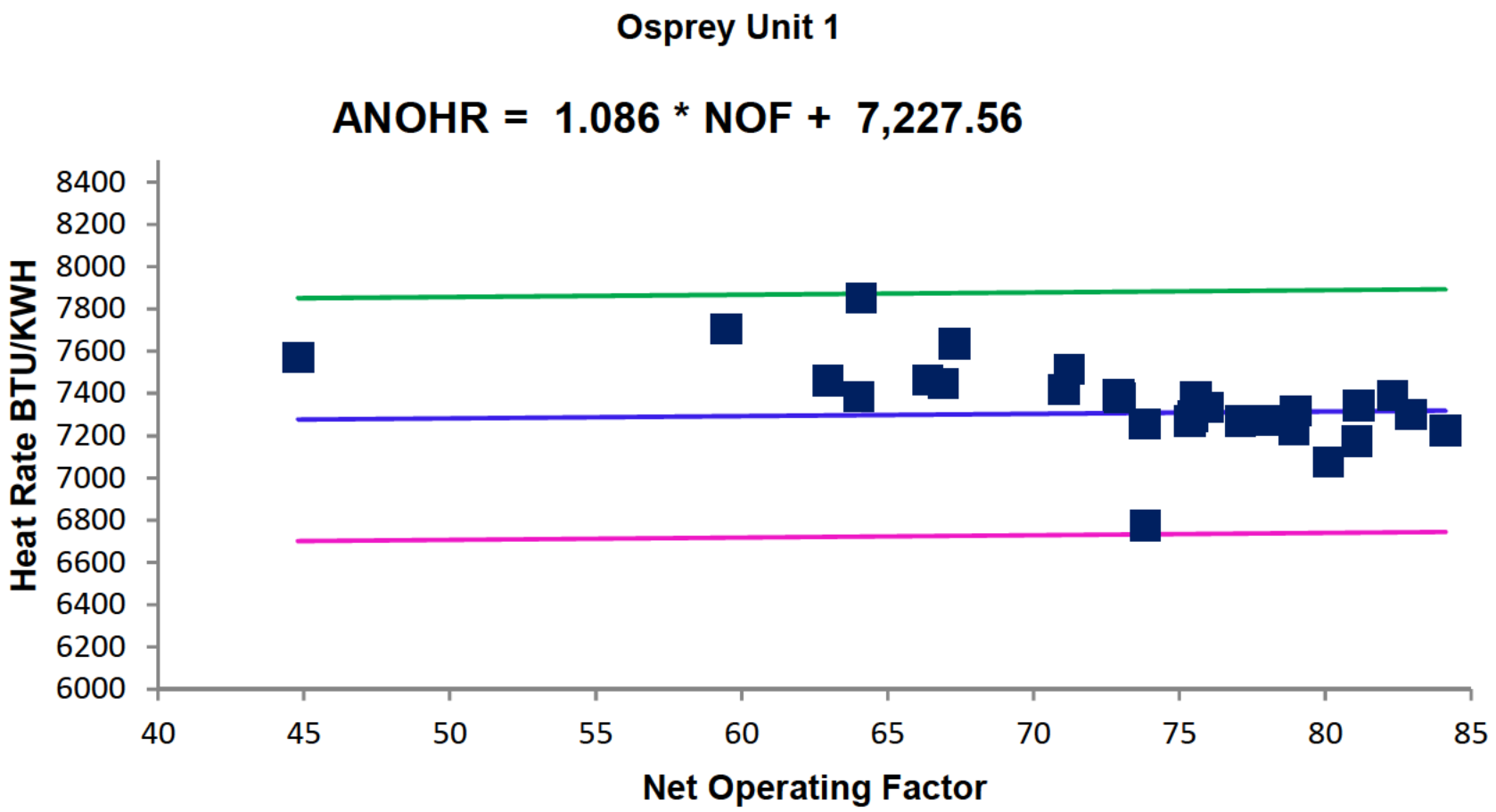
ANOHR = 1.086 * NOF + 7,227.56

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-16	84.1	7,226	7,319	-92.9	574.7
Aug-16	82.3	7,391	7,317	73.6	574.7
Sep-16	76.0	7,336	7,310	25.5	574.7
Oct-16	71.0	7,418	7,305	112.9	574.7
Nov-16	75.4	7,269	7,309	-40.0	574.7
Dec-16	67.3	7,636	7,301	335.6	574.7
Jan-17	53.1	5,767	7,285	-1518.1	574.7
Feb-17	66.4	7,466	7,300	166.6	574.7
Jul-17	79.0	7,319	7,313	5.4	574.7
Aug-17	82.9	7,301	7,318	-16.7	574.7
Sep-17	75.6	7,387	7,310	77.4	574.7
Oct-17	81.1	7,173	7,316	-142.3	574.7
Nov-17	71.2	7,514	7,305	208.6	574.7
Dec-17	75.5	7,292	7,310	-18.0	574.7
Jan-18	77.1	7,271	7,311	-40.3	574.7
Apr-18	59.5	7,706	7,292	413.4	574.7
May-18	66.9	7,446	7,300	145.6	574.7
Jun-18	78.9	7,230	7,313	-83.8	574.7
Jul-18	78.1	7,274	7,312	-38.8	574.7
Aug-18	64.0	7,387	7,297	89.6	574.7
Sep-18	81.1	7,342	7,316	26.7	574.7
Oct-18	73.8	7,255	7,308	-52.5	574.7
Nov-18	72.9	7,393	7,307	86.7	574.7
Dec-18	64.1	7,851	7,297	554.2	574.7
Jan-19	44.8	7,572	7,276	295.7	574.7
Feb-19	63.0	7,459	7,296	163.3	574.7
Mar-19	73.8	6,774	7,308	-533.9	574.7
Apr-19	75.4	7,273	7,309	-36.0	574.7
May-19	80.1	7,076	7,315	-239.0	574.7
Jun-19	72.9	7,378	7,307	71.4	574.7

Regression Output:

Constant	7227.56
Std Err of Y Est	355.3332613
R Squared	0.000793161
No. of Observations	30
Degrees of Freedom	28
X Coefficient	1.086425024
Std Err of Coef.	7.287317459


Osprey Unit 1
ANOHR = 1.086 * NOF + 7,227.56
Heat Rate BTU/KWH
8400
8200
8000
7800
7600
7400
7200
7000
6800
6600
6400
6200
6000
40
45
50
55
60
65
70
75
80
85
Net Operating Factor

UNPLANNED OUTAGE RATE TABLES AND GRAPHS

Bartow
Unit 4

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
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	730.81	736.37	700.33	529.72	429.97	653.16	677.03	411.15	365.44	644.23	725 55	703.35	716.07	744.00	673.72	703.50	620.52	669.22
RSH	0.00	0.00	0.00	19.78	0.00	28.24	66.97	0.00	41.78	0.00	1.65	11.50	4.35	0.00	30.57	24.71	42.01	0.00
UH	13.19	7.63	19.67	194.50	291.03	62.60	0.00	260.85	335.78	75.77	16 80	5.15	23.58	0.00	15.71	15.79	58.47	74.78
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.82	30.75
FOH	13.19	7.08	19.67	112.38	291.03	62.60	0.00	233.06	292.09	75.77	8 01	5.15	23.58	0.00	7.01	0.67	3.68	0.00
MOH	0.00	0.56	0.00	82.12	0.00	0.00	0.00	27.79	2.65	0.00	8.79	0.00	0.00	0.00	8.70	15.12	0.97	44.03
PFOH	34.39	51.99	89.01	12.04	0.00	0.00	0.00	0.00	0.00	203.76	521.64	292.50	313.68	288.85	279.53	315.66	279.92	288.85
LRPF	297.87	163.49	44.29	179.07	0.00	0.00	0.00	0.00	0.00	84.00	78.74	83.49	78.98	84.00	81.39	82.28	84.00	71.19
EFOH	8.82	7.31	3.39	1.86	0.00	0.00	0.00	0.00	0.00	15.49	37.17	22.10	22.42	21.96	20.59	23.50	21.28	18.61
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.45	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	46.49	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	0.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	1162.00	1162.00	1162.00	1162.00	1162.00	1162.00	1105.00	1105.00	1105.00	1105.00	1105 00	1105.00	1105.00	1105.00	1105.00	1105.00	1105.00	1105.00

MONTHLY	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
FOR	1.77	0.95	2.73	17.50	40.36	8.75	0.00	36.18	44.42	10.52	1 09	0.73	3.19	0.00	1.03	0.10	0.59	0.00
MOR	0.00	0.08	0.00	13.42	0.00	0.00	0.00	6.33	0.72	0.00	1 20	0.00	0.00	0.00	1.27	2.10	0.16	6.17
PFOR	1.21	0.99	0.48	0.35	0.00	0.00	0.00	0.00	0.00	2.40	5.12	3.14	3.13	2.95	3.06	3.34	3.43	2.78
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	2.96	2.01	3.20	27.11	40.36	8.75	0.00	38.82	44.65	12.67	7.40	3.85	6.22	2.95	5.26	5.46	4.15	8.78
EUOF	2.96	2.01	3.20	26.39	40.36	8.41	0.00	38.82	39.67	12.67	7 38	3.78	6.18	2.95	5.04	5.28	3.60	8.42
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.52	0.00	0 00	0.00	0.00	0.00	0.00	0.00	7.46	4.13
EAF	97.04	97.99	96.80	73.61	59.64	91.59	100.00	61.18	54.81	87.33	92.62	96.22	93.82	97.05	94.96	94.72	88.94	87.45

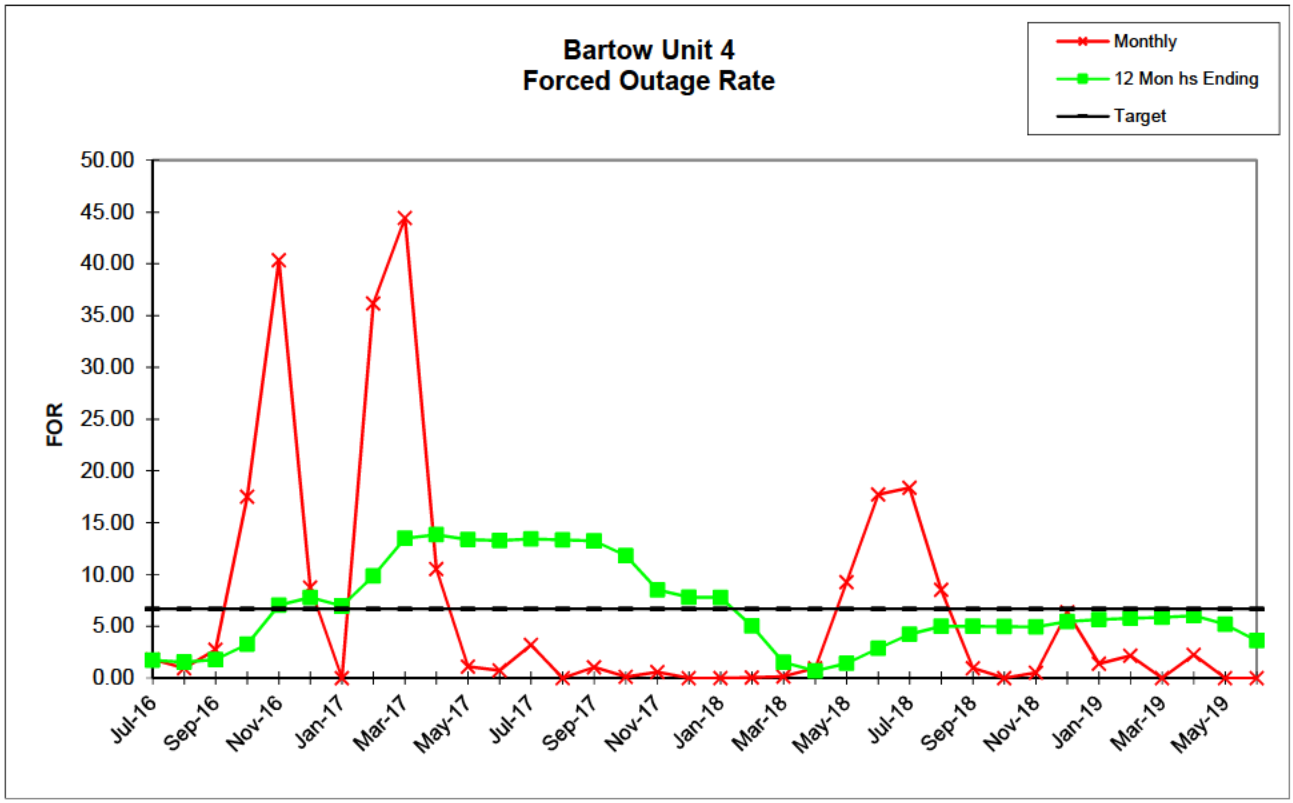
12 MONTHS	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
FOR	1.71	1.53	1.79	3.26	7.03	7.78	6.94	9.85	13.50	13.83	13 38	13.29	13.42	13.34	13.25	11.83	8.52	7.82
MOR	1.35	1.05	0 83	1.94	1.98	1.22	1.22	1.66	1.74	1.67	1.66	1.64	1.64	1.64	1.76	0.84	0.83	1.39
PFOR	0.21	0.31	0.28	0.30	0.31	0.31	0.31	0.32	0.33	0.54	1 03	1.32	1.50	1.70	1.95	2.19	2.42	2.65
PMOR	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
EUOR	3.21	2.86	2.86	5.36	9.02	9.11	8.28	11.48	15.09	15.53	15 52	15.66	15.95	16.03	16.25	14.41	11.42	11.43
EUOF	2.70	2.40	2.42	4.65	7.97	8.02	7.26	10.10	13.47	14.47	14 97	15.29	15.56	15.64	15.79	14.00	10.97	10.97
POF	14.41	14.41	14 20	11.72	10.34	10.34	10.34	10.37	8.89	5.00	1.70	0.47	0.47	0.47	0.47	0.47	1.08	1.43
EAF	82.90	83.19	83 38	83.63	81.69	81.64	82.40	79.53	77.64	80.53	83 33	84.25	83.97	83.89	83.74	85.53	87.95	87.59

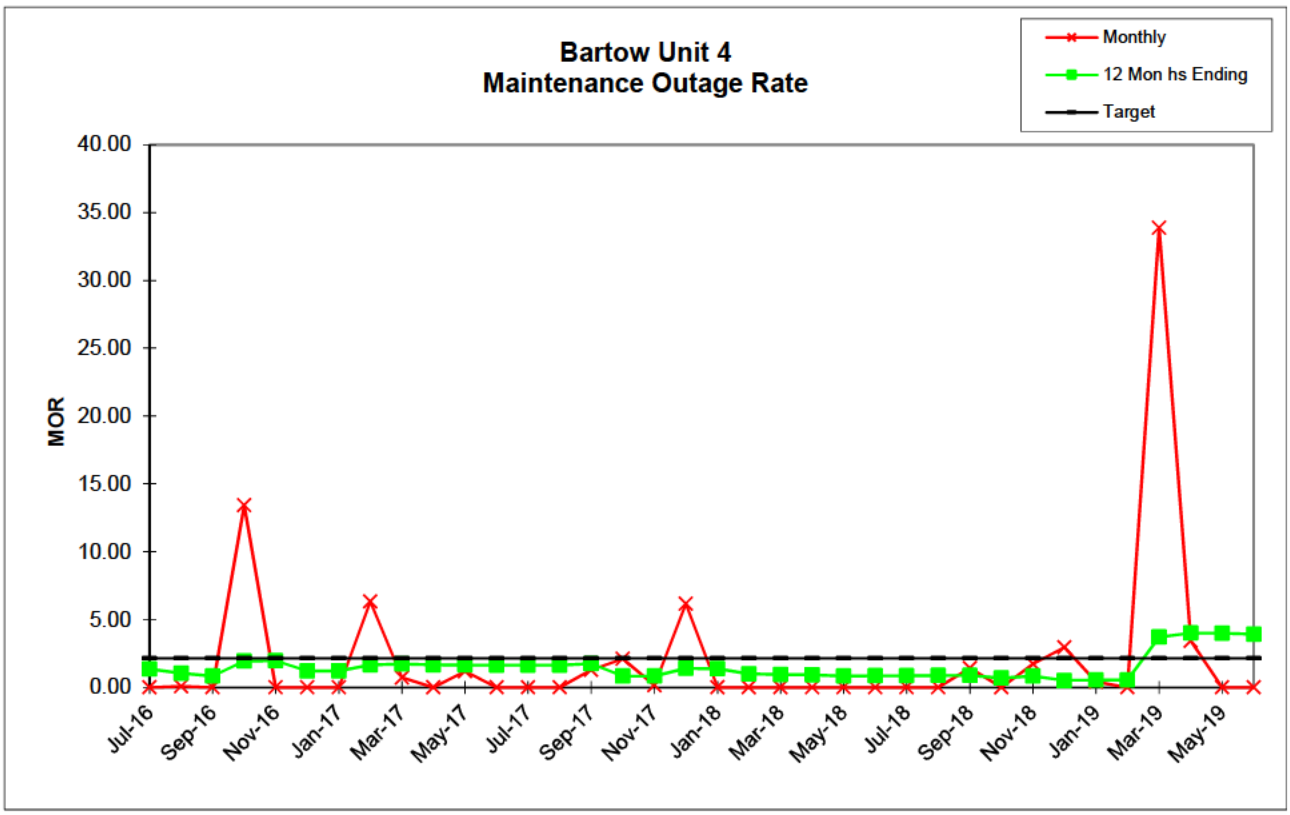
Bartow
Unit 4

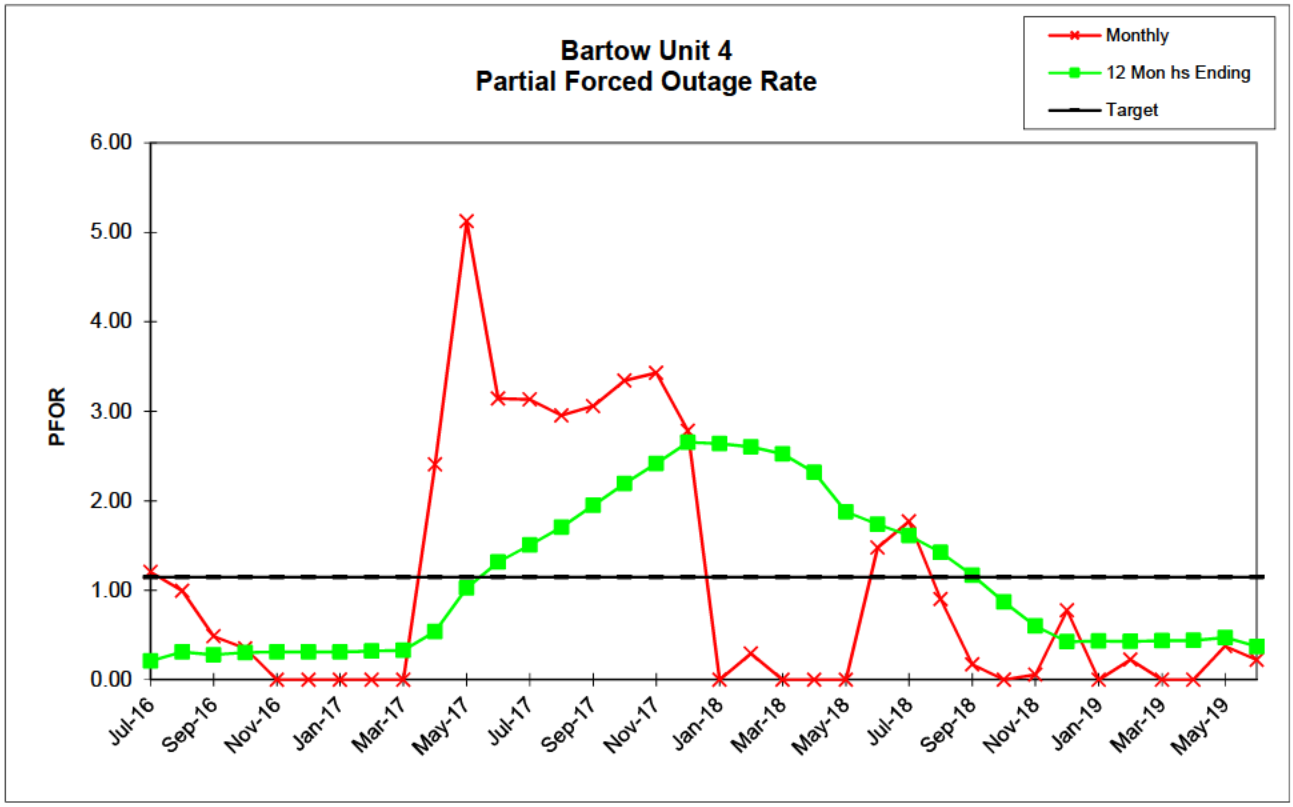
	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721 00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	723.12	576.01	617.32	699.21	660.66	586.42	601.19	675.79	702.70	708.62	654 33	605.85	603.93	593.93	485.47	612.30	711.99	695.10
RSH	20.88	95.74	13.25	14.12	15.97	7.14	7.57	5.18	0.51	35.38	23 94	55.22	129.03	65.02	8.72	1.31	32.01	24.90
UH	0.00	0.25	112.43	6.67	67.37	126.44	135.24	63.03	16.79	0.00	42.73	82.93	11.03	13.05	248.81	106.39	0.00	0.00
POH	0.00	0.00	111.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.77	23.38	0.00	0.00	0.00	70.58	0.00	0.00
FOH	0.00	0.25	0.78	6.67	67.37	126.44	135.24	63.03	6.61	0.00	3 35	41.02	8.52	13.05	0.00	14.09	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.18	0.00	11.61	18.53	2.51	0.00	248.81	21.72	0.00	0.00
PFOH	0.00	15.09	0.00	0.00	0.00	229.23	247.90	139.46	19.28	0.00	6 06	75.65	0.00	21.61	0.00	0.00	15.36	24.79
LRPF	0.00	120.02	0.00	0.00	0.00	40.82	46.36	47.15	66.99	0.00	67 04	67.00	0.00	66.98	0.00	0.00	186.98	67.00
EFOH	0.00	1.68	0.00	0.00	0.00	8.66	10.64	6.09	1.20	0.00	0 38	4.69	0.00	1.34	0.00	0.00	2.66	1.54
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21 27	0.00	0.00	0.00	182.68	0.00	17.83	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67 00	0.00	0.00	0.00	187.00	0.00	187.01	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1 32	0.00	0.00	0.00	31.63	0.00	3.09	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

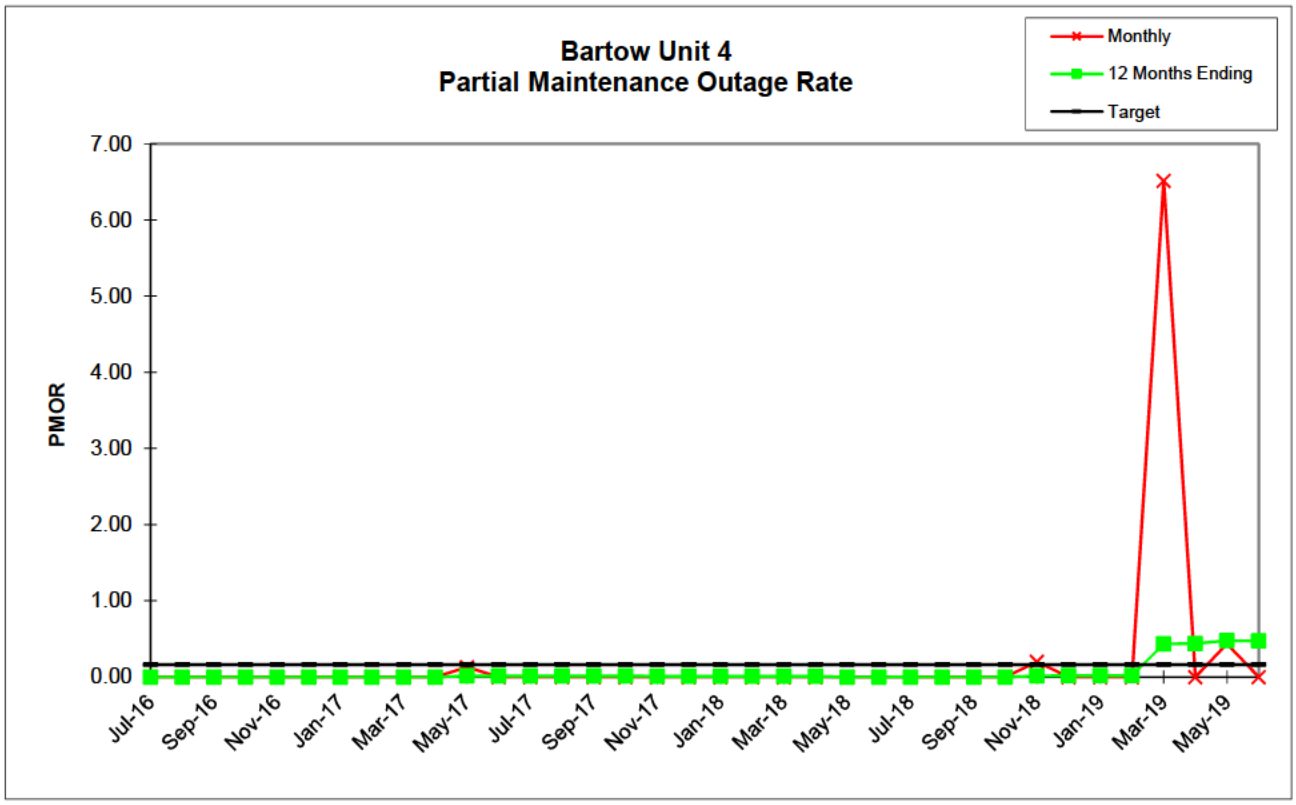
MONTHLY	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
FOR	0.00	0.04	0.13	0.94	9.25	17.74	18.36	8.53	0.93	0.00	0 51	6.34	1.39	2.15	0.00	2.25	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.43	0.00	1.74	2.97	0.41	0.00	33.88	3.43	0.00	0.00
PFOR	0.00	0.29	0.00	0.00	0.00	1.48	1.77	0.90	0.17	0.00	0 06	0.77	0.00	0.23	0.00	0.00	0.37	0.22
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 20	0.00	0.00	0.00	6.52	0.00	0.43	0.00
EUOR	0.00	0.33	0.13	0.94	9.25	18.95	19.81	9.36	2.50	0.00	2.49	9.65	1.79	2.37	38.19	5.53	0.81	0.22
EUOF	0.00	0.29	0.10	0.93	9.06	18.76	19.61	9.29	2.50	0.00	2 31	8.63	1.48	2.14	37.74	4.97	0.77	0.21
POF	0.00	0.00	15.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3 85	3.14	0.00	0.00	0.00	9.80	0.00	0.00
EAF	100.00	99.71	84.87	99.07	90.94	81.24	80.39	90.71	97.50	100.00	93 84	88.22	98.52	97.86	62.26	85.22	99.23	99.79

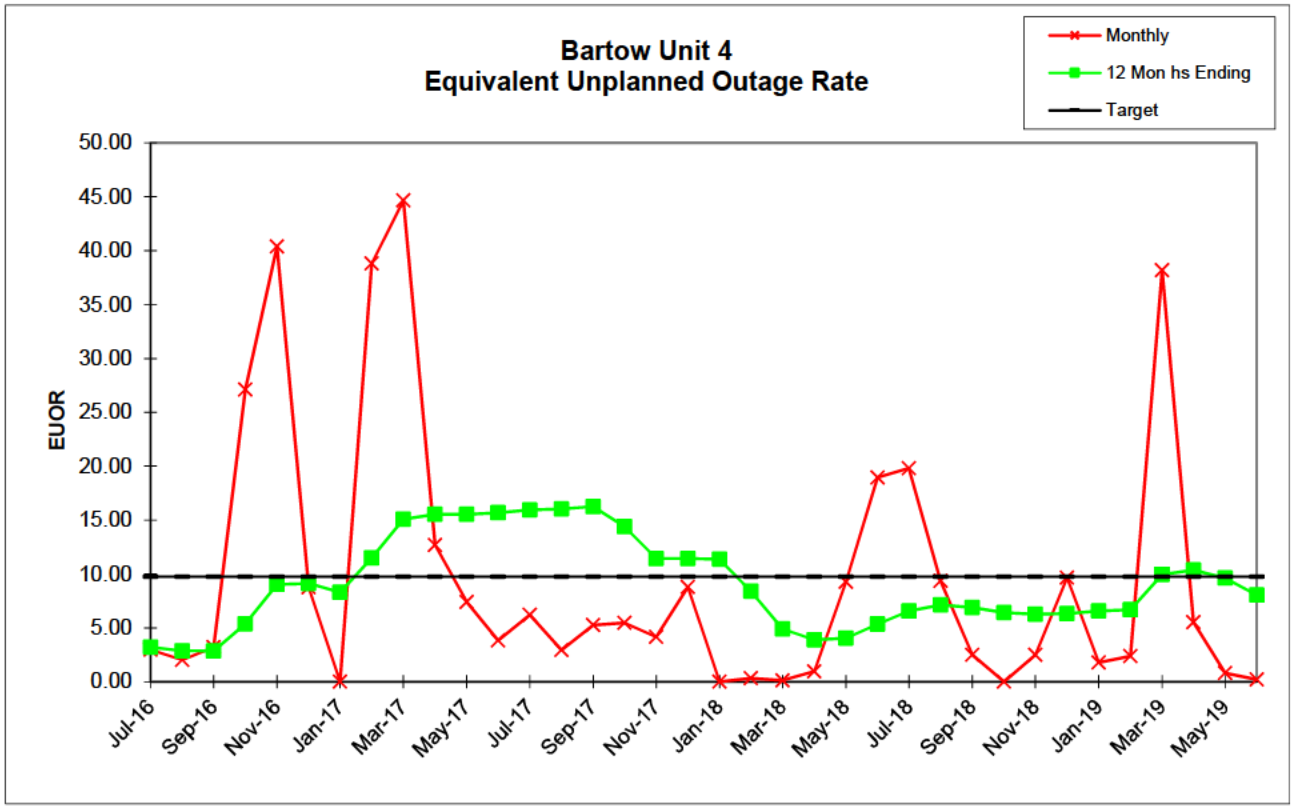
12 MONTHS	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
FOR	7.77	5.03	1.52	0.68	1.40	2.87	4.23	5.00	4.98	4.97	4 95	5.46	5.63	5.77	5.86	6.01	5.17	3.59
MOR	1.38	1.01	0.95	0.94	0.84	0.85	0.87	0.87	0.89	0.70	0 83	0.51	0.55	0.55	3.71	4.02	3.99	3.93
PFOR	2.64	2.60	2.52	2.32	1.88	1.74	1.61	1.42	1.17	0.87	0.60	0.43	0.43	0.43	0.44	0.44	0.47	0.37
PMOR	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0 02	0.02	0.02	0.02	0.43	0.44	0.48	0.47
EUOR	11.37	8.40	4.91	3.90	4.05	5.35	6.56	7.13	6.89	6.42	6 28	6.33	6.55	6.68	9.94	10.36	9.63	8.03
EUOF	10.97	8.02	4.66	3.69	3.84	5.07	6.21	6.75	6.54	6.09	5 98	6.00	6.13	6.27	9.46	9.79	9.09	7.57
POF	1.43	1.43	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	1 94	1.86	1.86	1.86	0.58	1.39	1.39	1.39
EAF	87.59	90.55	93.10	94.07	93.92	92.69	91.55	91.01	91.22	91.67	92 07	92.14	92.01	91.87	89.95	88.82	89.52	91.04

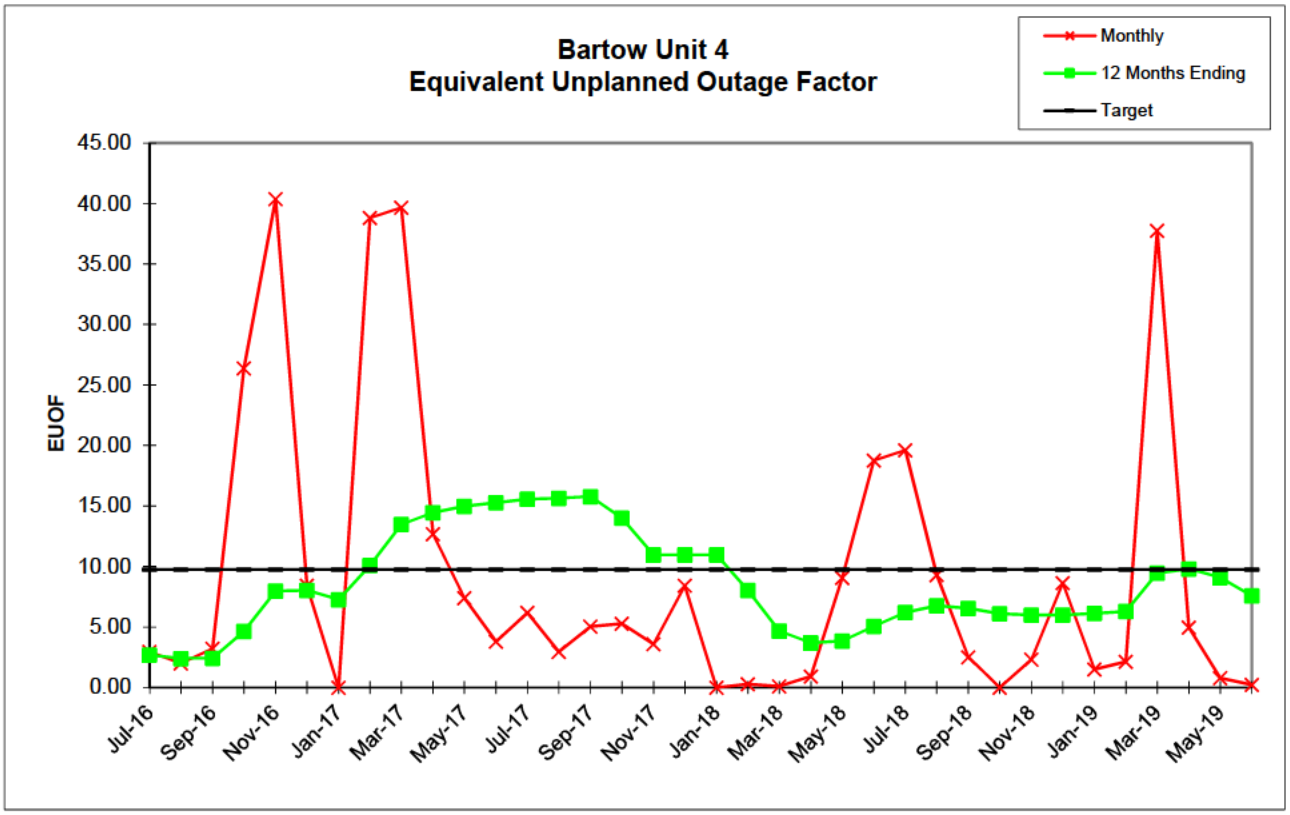

Bartow Unit 4
Forced Outage Rate
Monthly
12 Mon hs Ending
Target
FOR
50.00
45.00
40.00
35.00
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Bartow Unit 4
Maintenance Outage Rate
Monthly
12 Mon hs Ending
Target
MOR
40.00
35.00
30.00
25.00
20.00
15.00
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Bartow Unit 4
Partial Forced Outage Rate
Monthly
12 Mon hs Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-16
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Bartow Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
7.00
6.00
5.00
4.00
3.00
2.00
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Jul-16
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Bartow Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Mon hs Ending
Target
EUOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
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Jul-16
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Bartow Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
45.00
40.00
35.00
30.00
25.00
20.00
15.00
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Jul-16
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May-19

Hines
Unit 1

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18
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	744.00	672.00
SER HOURS	722.54	744.00	720.00	726.12	686.68	635.23	603.32	672.00	736.42	112.79	514.80	641 24	722.54	724.19	662.30	653.40	691.81	621.65	714.50	672.00
RSH	0.00	0.00	0.00	0.00	34.32	99.79	140.68	0.00	0.05	0.00	134.79	0 00	1.42	19.81	57.70	40.66	19.01	98.75	16.65	0.00
UH	21.46	0.00	0.00	17 88	0.00	8.97	0.00	0.00	6.53	607.21	94.41	78.76	20.04	0.00	0.00	49.95	10.17	23.60	12.85	0.00
POH	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	6.53	607.21	61.69	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	21.46	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	32.72	78.76	20.04	0.00	0.00	3.90	10.17	23.60	12.85	0.00
MOH	0.00	0.00	0.00	17 88	0.00	8.97	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	46.05	0.00	0.00	0.00	0.00
PFOH	22.74	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	287.40	83.45	22.74	0.00	0.00	2.67	0.00	4.10	12.44	0.00
LRPF	105.38	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	60.82	68.18	108.05	0.00	0.00	77.98	0.00	99.00	69.78	0.00
EFOH	4.63	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	33.81	11.00	4.75	0.00	0.00	0.40	0.00	0.79	1.75	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	4.85	17.06	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	99.01	99.02	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	0.93	3.27	0.00	0.00
NPC	518.00	518.00	518.00	518 00	518.00	518.00	517.00	517.00	517.00	517.00	517.00	517 00	517.00	517.00	517.00	517.00	517.00	517.00	495.00	495.00

MONTHLY	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**
FOR	2.88	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	5.98	10 94	2.70	0.00	0.00	0.59	1.45	3.66	1.77	0.00
MOR	0.00	0.00	0.00	2.40	0.00	1.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.58	0.00	0.00	0.00	0.00
PFOR	0.64	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	6.57	1.72	0.66	0.00	0.00	0.06	0.00	0.13	0.25	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	0.13	0.53	0.00	0.00
EUOR	3.51	0.00	0.00	2.40	0.00	1.39	0.00	0.00	0.00	0.00	12.15	12.47	3.34	0.00	0.00	7.16	1.58	4.29	2.01	0.00
EUOF	3.51	0.00	0.00	2.40	0.00	1.21	0.00	0.00	0.00	0.00	8.94	12.47	3.33	0.00	0.00	6.77	1.54	3.72	1.96	0.00
POF	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.88	84.33	8.29	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	96.49	100.00	100.00	97.60	100.00	98.79	100.00	100.00	99.12	15.67	82.77	87.53	96.67	100.00	100.00	93.23	98.46	96.28	98.04	100.00

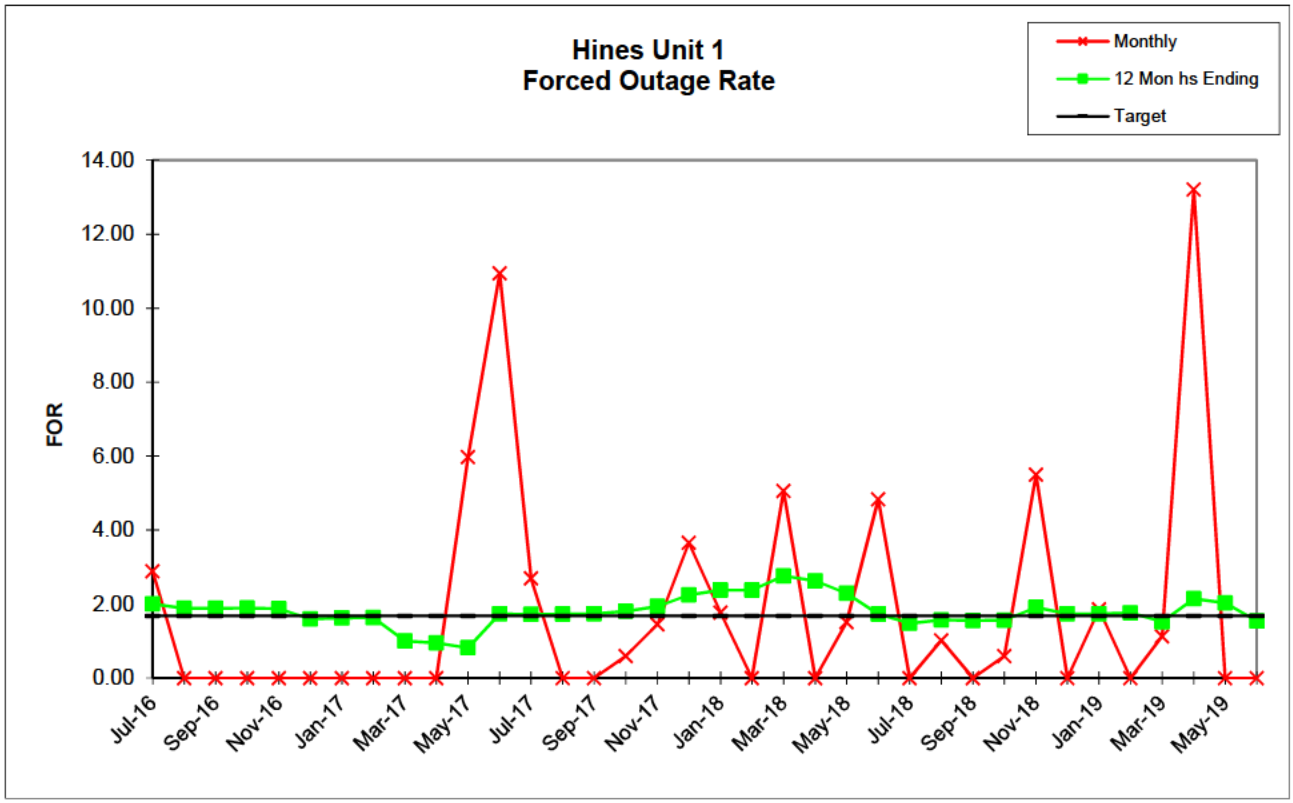
12 MONTHS	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**
FOR	2.01	1.88	1.88	1 89	1.87	1.60	1.62	1.63	1.00	0.95	0.81	1.74	1.72	1.72	1.74	1.81	1.94	2.25	2.38	2.38
MOR	0.00	0.00	0.00	0 23	0.23	0.35	0.36	0.36	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.74	0.74	0.62	0.61	0.61
PFOR	0.11	0.08	0.08	0 08	0.08	0.08	0.09	0.09	0.08	0.08	0.53	0.66	0.66	0.66	0.67	0.68	0.68	0.69	0.70	0.70
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	0.01	0.06	0.06	0.06
EUOR	2.11	1.97	1.97	2.19	2.18	2.02	2.06	2.06	1.42	1.37	1.69	2.73	2.71	2.72	2.74	3.18	3.32	3.57	3.70	3.70
EUOF	1.88	1.75	1.75	1 95	1.94	1.78	1.78	1.79	1.27	1.22	1.48	2.39	2.37	2.37	2.37	2.74	2.87	3.08	3.25	3.25
POF	10.11	10.11	10.11	10.11	10.11	10.11	10.11	10.14	7.76	7.57	7.71	7.71	7.71	7.71	7.71	7.71	7.71	7.71	7.71	7.71
EAF	88.02	88.14	88.14	87 94	87.95	88.11	88.11	88.08	90.97	91.20	90.81	89.90	89.92	89.92	89.92	89.55	89.42	89.21	89.04	89.04

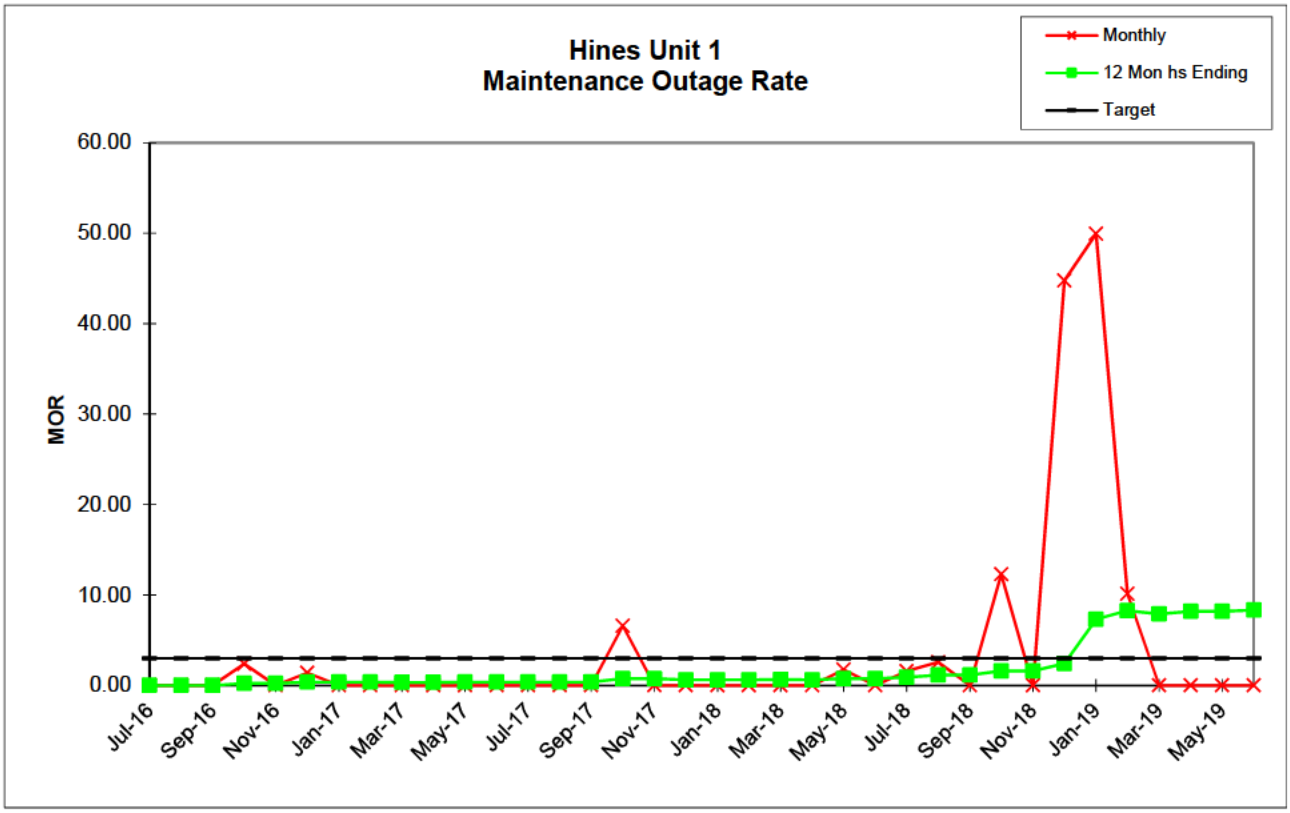
Hines
Unit 1

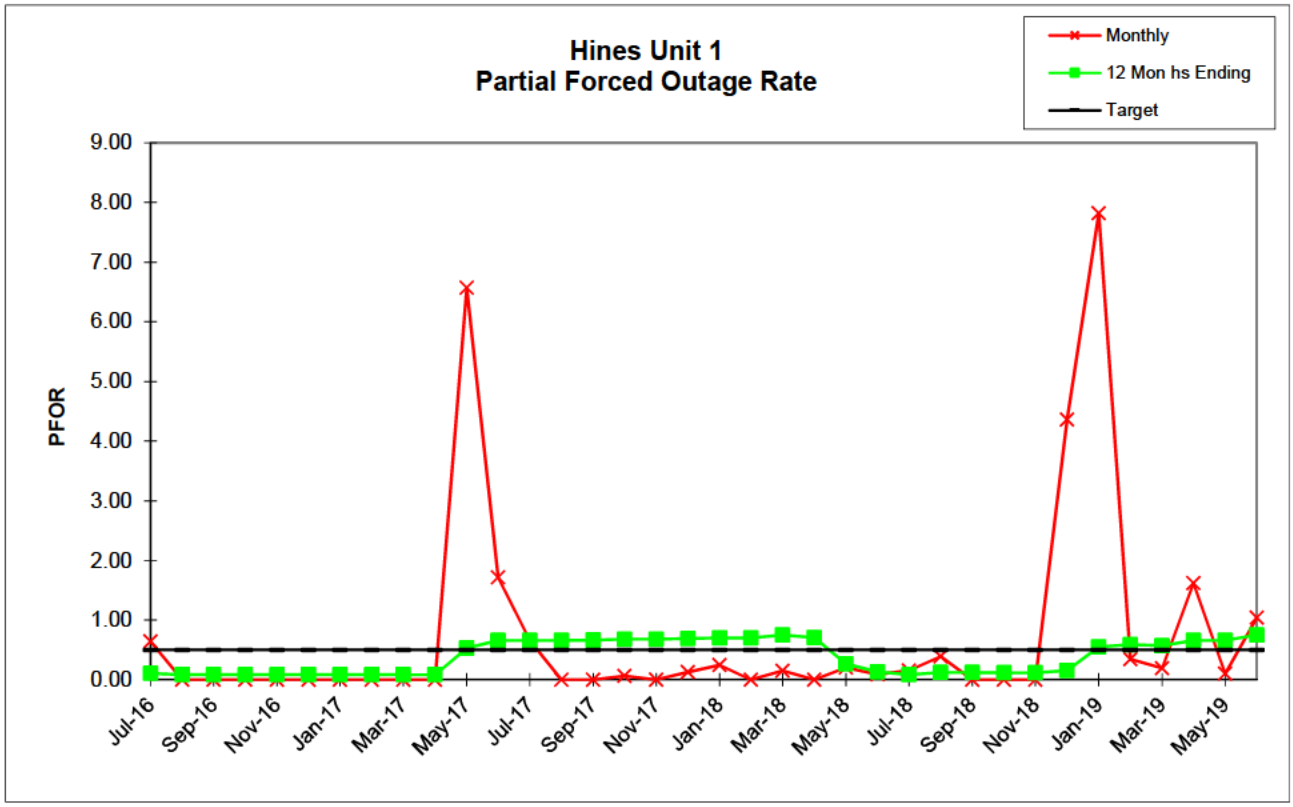
	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
PER HOURS	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744 00	672.00	743.00	720.00	744.00	720.00
SER HOURS	363.69	495.04	704.70	685.18	732.31	715.07	720.00	580.80	621.72	61.63	356.18	588.34	669.00	259.95	562.87	555.81
RSH	0.05	0.02	15.99	0.00	0.00	2.76	0.00	78.31	63.08	632.44	25.73	17.44	66.37	28.53	181.13	164.19
UH	379.26	224.94	23.31	34.82	11.69	26.18	0.00	84.88	36.20	49.93	362 09	66.22	7.63	431.52	0.00	0.00
POH	359.88	224.94	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	391.94	0.00	0.00
FOH	19.38	0.00	10.84	34.82	0.00	7.36	0.00	3.45	36.20	0.00	6.74	0.00	7.63	39.58	0.00	0.00
MOH	0.00	0.00	12.47	0.00	11.69	18.82	0.00	81.44	0.00	49.93	355 35	66.22	0.00	0.00	0.00	0.00
PFOH	3.56	0.00	10.38	4.32	10.93	22.54	0.00	0.00	0.00	18.06	166.45	12.02	7.32	26.28	5.36	69.26
LRPF	76.57	0.00	67.60	69.07	51.62	61.35	0.00	0.00	0.00	73.61	82 00	82.02	85.08	78.36	51.29	40.97
EFOH	0.55	0.00	1.42	0.60	1.14	2.79	0.00	0.00	0.00	2.69	27 85	2.01	1.27	4.20	0.56	5.79
PMOH	0.00	0.00	11.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	2.66	0.00	0.00
LRPM	0.00	0.00	67.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	78.11	0.00	0.00
EMOH	0.00	0.00	1.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.42	0.00	0.00
NPC	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	490 00	490.00	490.00	490.00	490.00	490.00

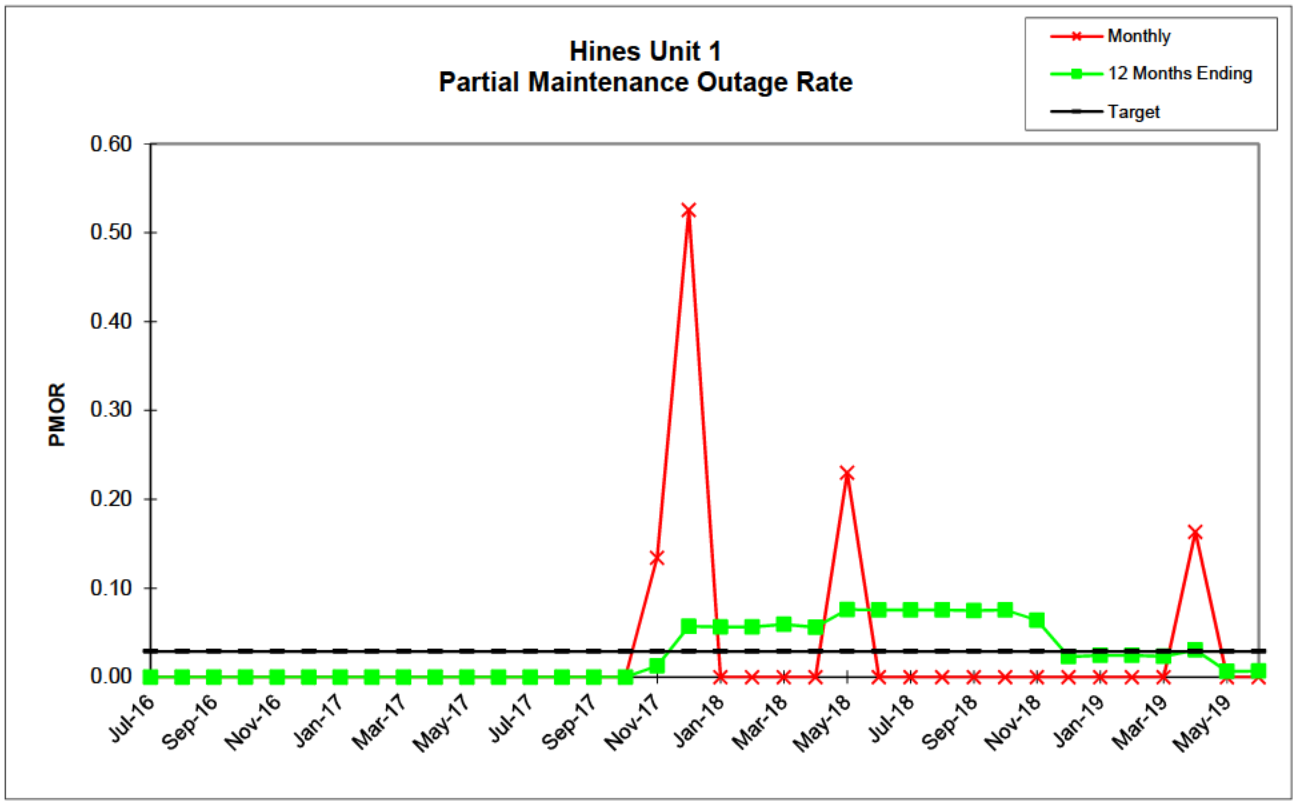
MONTHLY	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**
FOR	5.06	0.00	1.51	4.84	0.00	1.02	0.00	0.59	5.50	0.00	1 86	0.00	1.13	13.21	0.00	0.00
MOR	0.00	0.00	1.74	0.00	1.57	2.56	0.00	12.30	0.00	44.76	49 94	10.12	0.00	0.00	0.00	0.00
PFOR	0.15	0.00	0.20	0.09	0.16	0.39	0.00	0.00	0.00	4.36	7 82	0.34	0.19	1.62	0.10	1.04
PMOR	0.00	0.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.16	0.00	0.00
EUOR	5.20	0.00	3.62	4.92	1.72	3.91	0.00	12.75	5.50	47.16	54 29	10.42	1.32	14.76	0.10	1.04
EUOF	2.68	0.00	3.54	4.92	1.72	3.89	0.00	11.41	5.02	7.07	52.41	10.15	1.20	6.14	0.08	0.80
POF	48.44	31.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	54.44	0.00	0.00
EAF	48.88	68.76	96.46	95.08	98.28	96.11	100.00	88.59	94.98	92.93	47 59	89.85	98.80	39.42	99.92	99.20

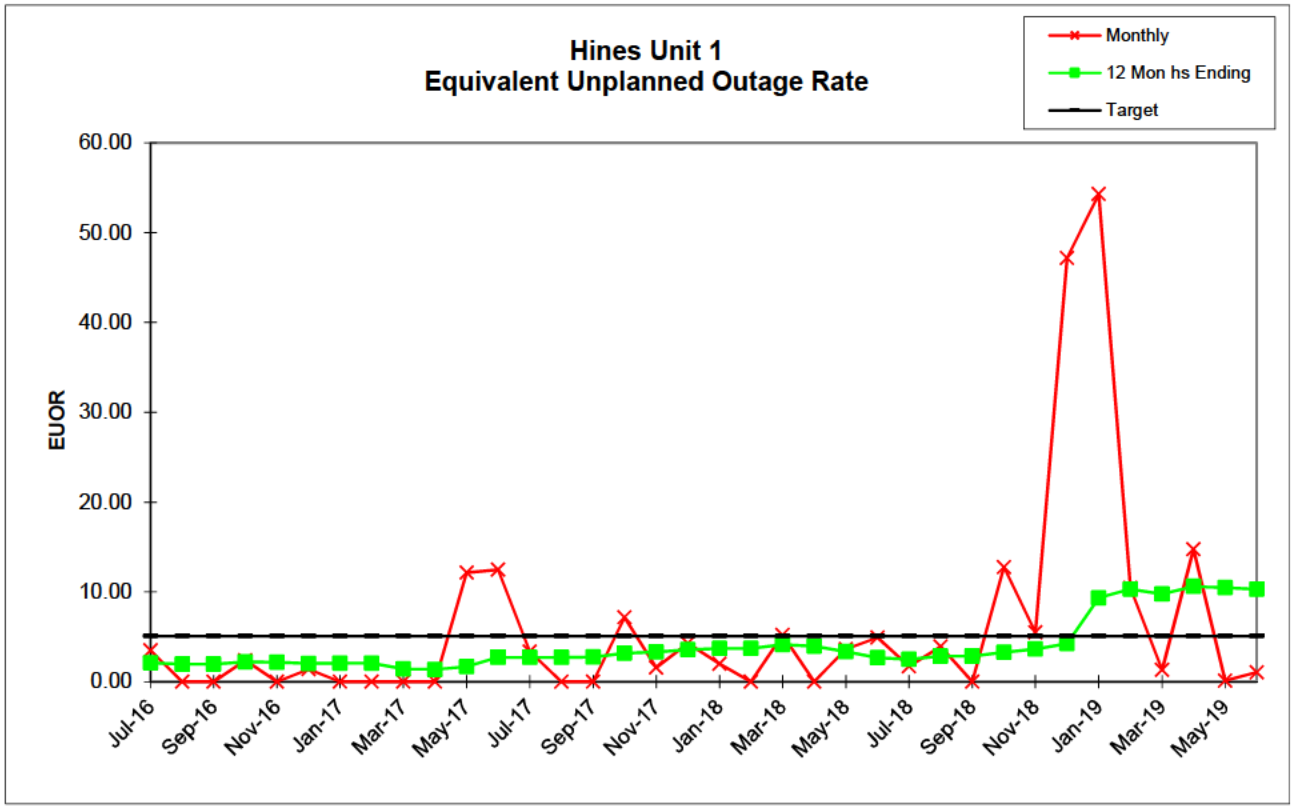
12 MONTHS	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**
FOR	2.76	2.62	2.29	1.73	1.47	1.57	1.56	1.57	1.91	1.74	1.74	1.76	1.52	2.14	2.03	1.55
MOR	0.64	0.61	0.76	0.75	0.90	1.14	1.13	1.59	1.61	2.41	7 32	8.25	7.92	8.17	8.18	8.33
PFOR	0.75	0.71	0.27	0.13	0.09	0.12	0.12	0.12	0.12	0.15	0 55	0.59	0.57	0.66	0.66	0.75
PMOR	0.06	0.06	0.08	0.08	0.08	0.08	0.07	0.08	0.06	0.02	0 02	0.02	0.02	0.03	0.01	0.01
EUOR	4.15	3.94	3.35	2.66	2.51	2.87	2.85	3.30	3.63	4.23	9 34	10.29	9.75	10.60	10.49	10.31
EUOF	3.48	3.48	3.02	2.40	2.26	2.59	2.59	2.99	3.27	3.56	7 84	8.62	8.50	9.00	8.71	8.37
POF	11.74	7.38	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	2.57	4.47	4.47	4.47
EAF	84.78	89.14	90 30	90.92	91.06	90.73	90.73	90.34	90.05	89.76	85.48	84.70	88.93	86.52	86.82	87.16

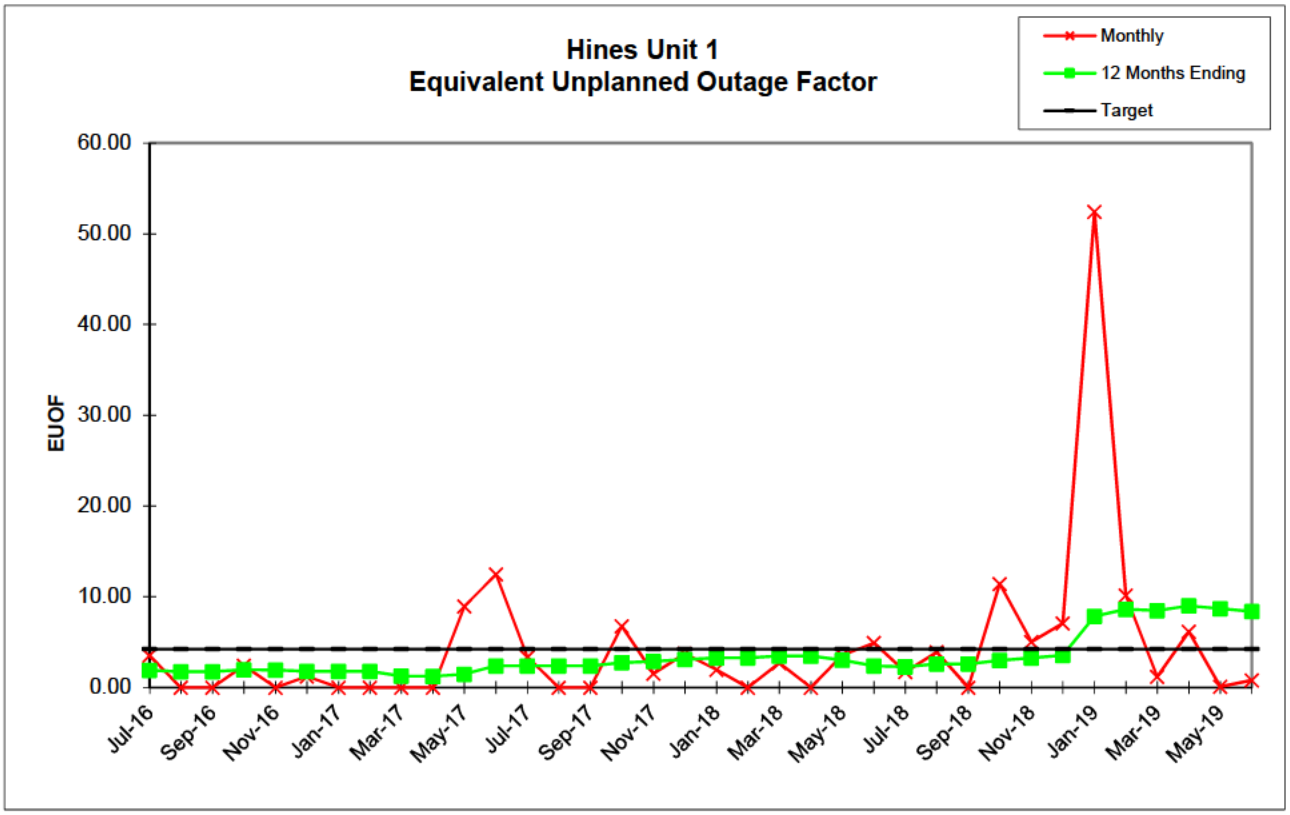

Hines Unit 1
Forced Outage Rate
Monthly
12 Mon hs Ending
Target
FOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-16
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Hines Unit 1
Maintenance Outage Rate
Monthly
12 Mon hs Ending
Target
MOR
60.00
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40.00
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Jul-16
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Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 1
Partial Forced Outage Rate
Monthly
12 Mon hs Ending
Target
PFOR
9.00
8.00
7.00
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4.00
3.00
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Jul-16
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Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
0.60
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May-19


Hines Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Mon hs Ending
Target
EUOR
60.00
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May-19


Hines Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
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May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19

Hines
Unit 2

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18
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	744 00	672.00	743.00
SER HOURS	744.00	605.51	667.52	736.82	542.18	611.63	646.18	419.64	743.00	672.69	744 00	720.00	738.76	719.49	507.02	148.41	654.39	487.29	693.32	464.52	669.67
RSH	0.00	0.00	17.97	1.05	91.70	126.42	97.82	252.36	0.00	47.31	0 00	0.00	0.00	0.00	14.89	95.14	58.38	256.71	50.68	204.00	2.22
UH	0.00	138.49	34.51	6.13	87.12	5.95	0.00	0.00	0.00	0.00	0 00	0.00	5.24	24.51	198.09	500.45	8.23	0.00	0.00	3.48	71.10
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	0.00	193.92	500.45	0.00	0.00	0.00	0.00	0.00
FOH	0.00	18.49	7.96	0.00	87.12	5.95	0.00	0.00	0.00	0.00	0 00	0.00	0.00	24.51	4.17	0.00	8.23	0.00	0 00	3.48	71.10
MOH	0.00	120.00	26.55	6.13	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	5.24	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00
PFOH	0.00	2.14	0.00	0.00	104.25	7.03	0.00	0.00	0.00	0.00	0 00	0.00	0.00	28.96	9.20	0.00	9.13	0.00	0 00	3.42	0.00
LRPF	0.00	120.56	0.00	0.00	116.80	116.74	0.00	0.00	0.00	0.00	0 00	0.00	0.00	132.44	133.33	0.00	117.43	0.00	0.00	92.32	0.00
EFOH	0.00	0.47	0.00	0.00	22.30	1.50	0.00	0.00	0.00	0.00	0 00	0.00	0.00	7.04	2.25	0.00	1.97	0.00	0 00	0.60	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	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	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	0.00	0.00	0.00
NPC	546.00	546.00	546.00	546.00	546.00	546.00	545.00	545.00	545.00	545.00	545 00	545.00	545.00	545.00	545.00	545.00	545.00	545.00	527.00	527.00	527.00

MONTHLY	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**
FOR	0.00	2.96	1.18	0.00	13.84	0.96	0.00	0.00	0.00	0.00	0 00	0.00	0.00	3.29	0.82	0.00	1.24	0.00	0 00	0.74	9.60
MOR	0.00	16.54	3.83	0.83	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.70	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00
PFOR	0.00	0.08	0.00	0.00	4.11	0.25	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.98	0.44	0.00	0.30	0.00	0 00	0.13	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	0 00	0.00	0.00
EUOR	0.00	18.68	4.92	0.83	17.39	1.21	0.00	0.00	0.00	0.00	0 00	0.00	0.70	4.24	1.26	0.00	1.54	0.00	0 00	0.87	9.60
EUOF	0.00	18.68	4.79	0.82	15.18	1.00	0.00	0.00	0.00	0.00	0 00	0.00	0.70	4.24	0.89	0.00	1.41	0.00	0 00	0.61	9.57
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	0.00	26.93	67.26	0.00	0.00	0 00	0.00	0.00
EAF	100.00	81.32	95.21	99.18	84.82	99.00	100.00	100.00	100.00	100.00	100 00	100.00	99.30	95.76	72.17	32.74	98.59	100.00	100.00	99.39	90.43

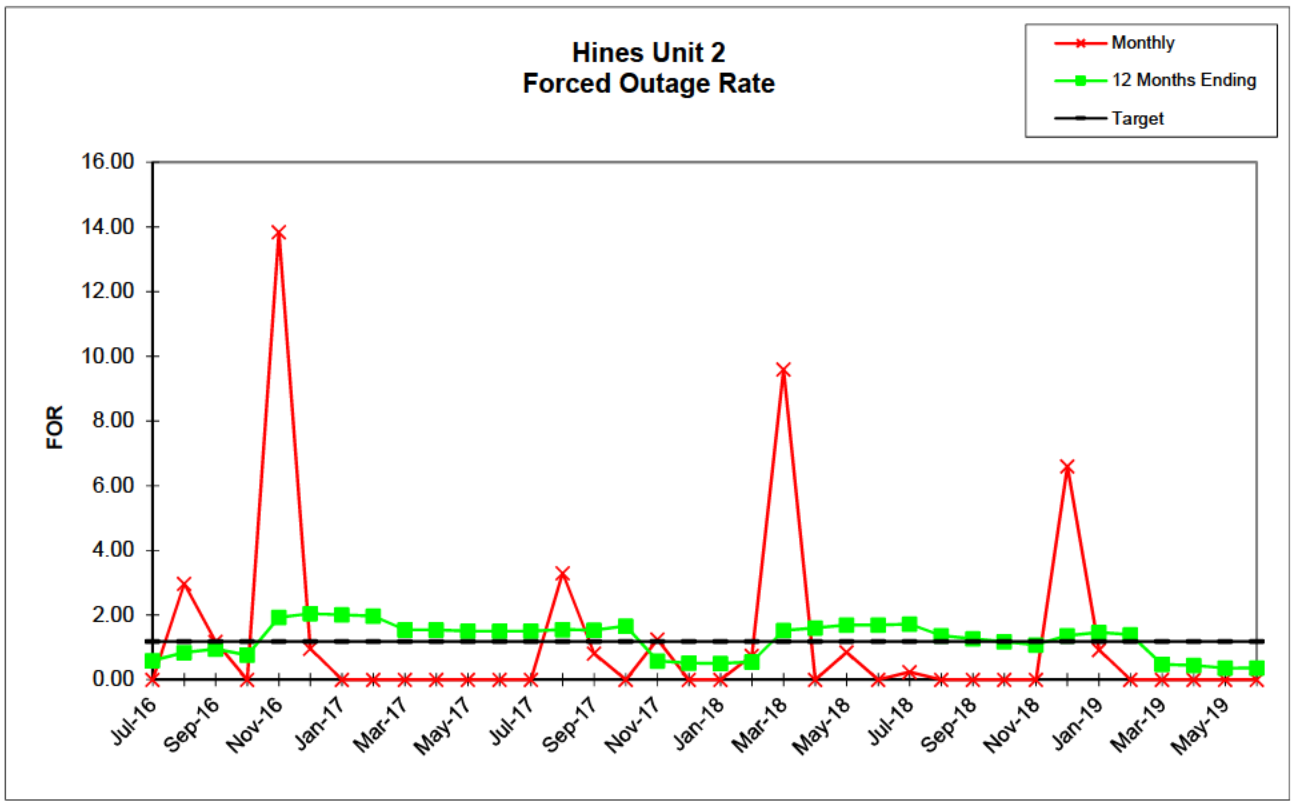
12 MONTHS	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**
FOR	0.59	0.84	0.95	0.76	1.93	2.04	2.01	1.96	1.54	1.54	1 50	1.50	1.50	1.55	1.54	1.66	0.58	0.51	0 51	0.55	1.52
MOR	0.07	1.64	1.98	2.06	2.10	2.14	2.14	2.11	1.97	1.98	1 91	1.91	1.97	0.47	0.15	0.07	0.07	0.07	0 07	0.07	0.07
PFOR	0.06	0.07	0.07	0.02	0.32	0.35	0.35	0.35	0.32	0.32	0 32	0.31	0.31	0.39	0.42	0.46	0.17	0.16	0.16	0.16	0.16
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	0.00	0.00	0.00
EUOR	0.72	2.52	2.95	2.81	4.26	4.43	4.40	4.33	3.76	3.77	3.66	3.65	3.71	2.39	2.09	2.18	0.83	0.74	0.73	0.78	1.75
EUOF	0.63	2.22	2.61	2.48	3.73	3.81	3.78	3.78	3.51	3.50	3.40	3.38	3.44	2.22	1.90	1.83	0.69	0.61	0.61	0.66	1.47
POF	8.73	8.73	8.73	8.73	8.73	8.73	8.73	6.02	0.00	0.00	0 00	0.00	0.00	0.00	2.21	7.93	7.93	7.93	7 93	7.93	7.93
EAF	90.63	89.05	88.66	88.79	87.54	87.46	87.49	90.21	96.49	96.50	96.60	96.62	96.56	97.78	95.89	90.25	91.38	91.46	91.46	91.42	90.61

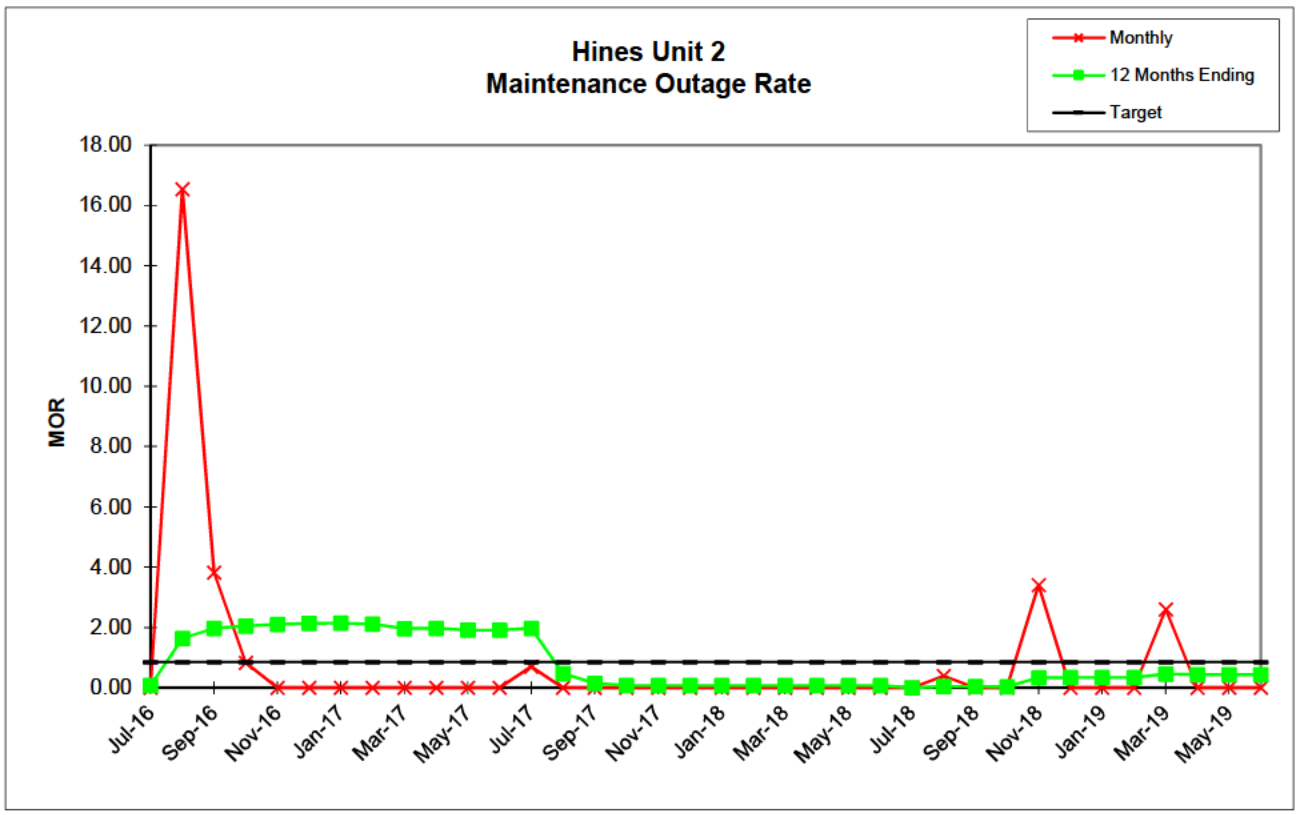
Hines
Unit 2

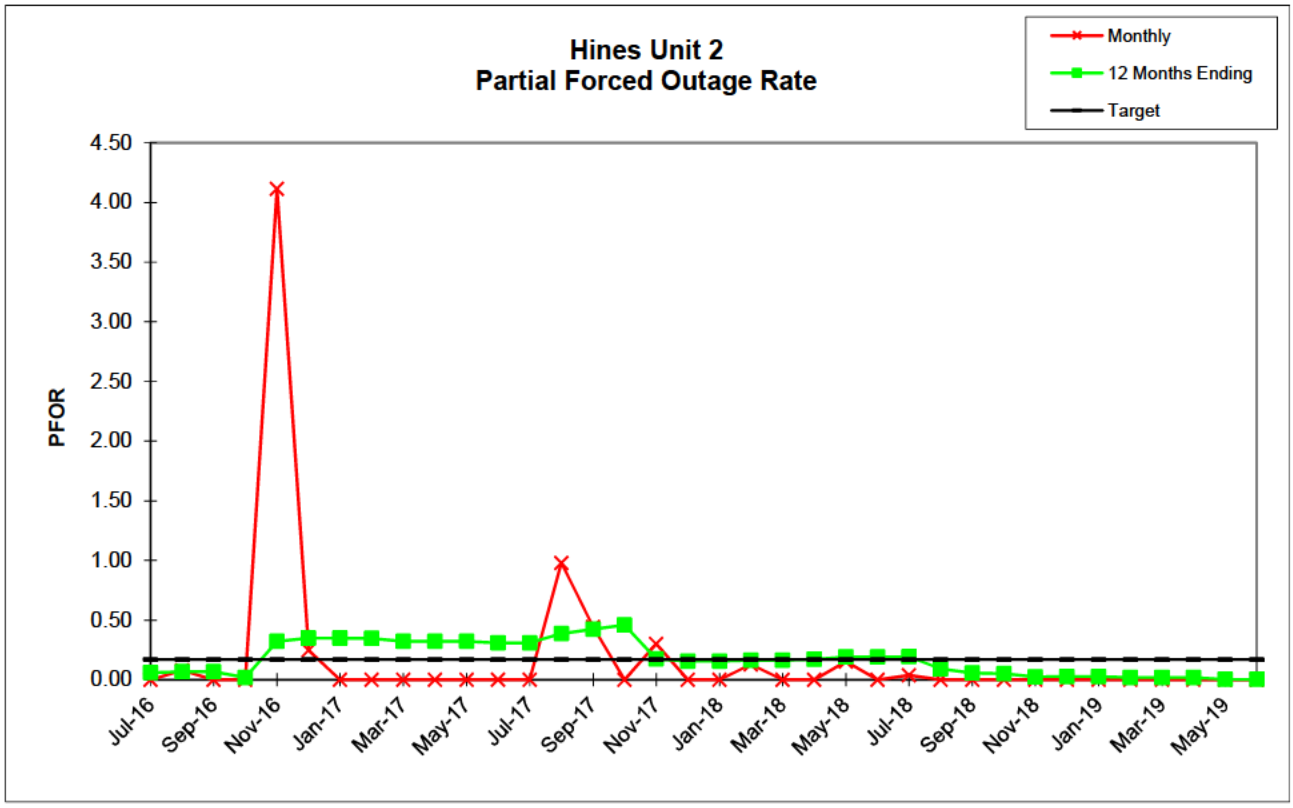
	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
PER HOURS	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672 00	743.00	720.00	744.00	720.00
SER HOURS	313.00	703.73	720.00	742.21	741.04	720.00	712.89	625.29	285.04	522.14	594.16	262.42	703.77	741.59	693.36
RSH	0.01	0.59	0.00	0.00	0.00	0.00	31.11	73.62	438.84	217.02	77 84	142.29	16.23	2.41	26.64
UH	406.99	39.68	0.00	1.79	2.96	0.00	0.00	22.09	20.13	4.84	0 00	7.00	0.00	0.00	0.00
POH	406.99	33.66	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	6.02	0.00	1.79	0.00	0.00	0.00	0.00	20.13	4.84	0 00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	2.96	0.00	0.00	22.09	0.00	0.00	0 00	7.00	0.00	0.00	0.00
PFOH	0.00	6.20	0.00	1.76	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	90.96	0.00	86.19	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	1.07	0.00	0.29	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	2.91	0.00	0.00	22.76	0.00	0.00	0 00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	94.40	0.00	0.00	80.33	0.00	0.00	0 00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.52	0.00	0.00	3.47	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	527.00	527.00	527.00	512.00	512 00	512.00	512.00	512.00	512.00

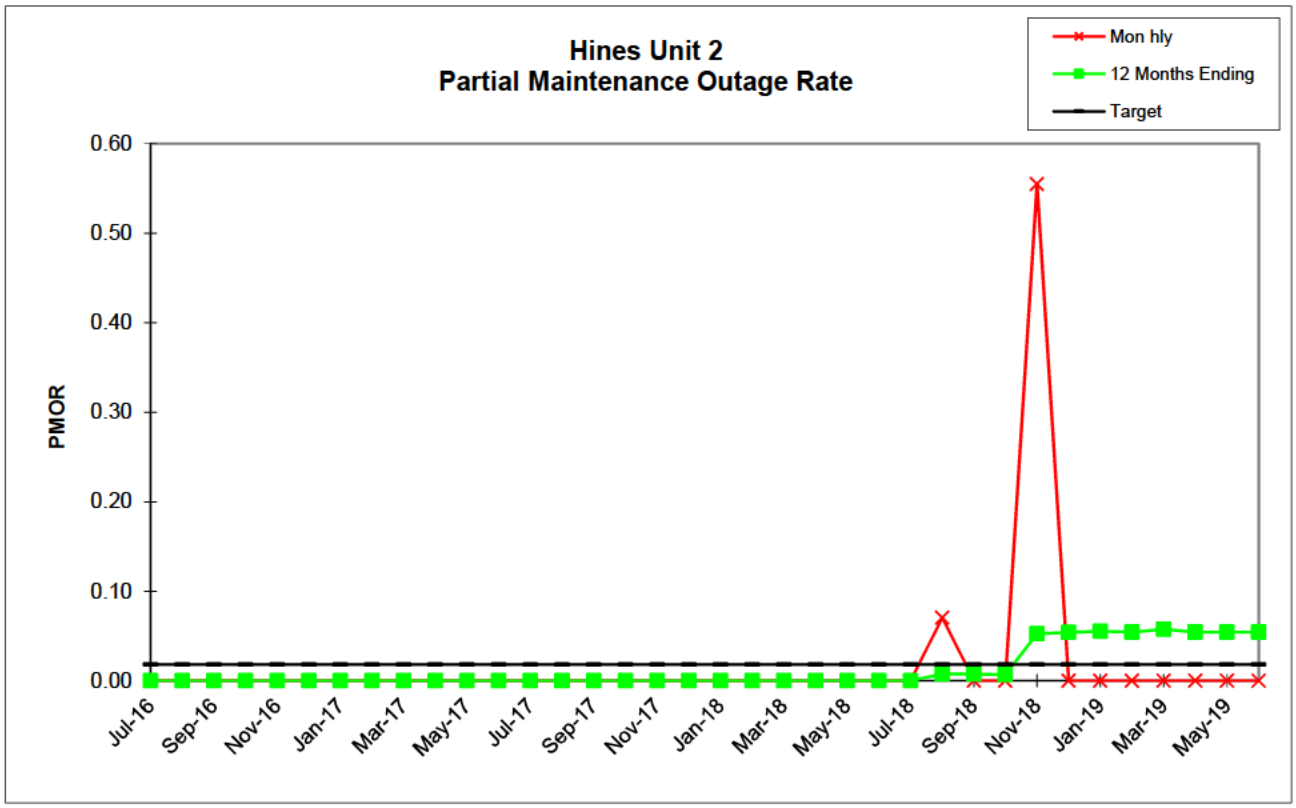
MONTHLY	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**
FOR	0.00	0.85	0.00	0.24	0.00	0.00	0.00	0.00	6.60	0.92	0 00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.40	0.00	0.00	3.41	0.00	0.00	0 00	2.60	0.00	0.00	0.00
PFOR	0.00	0.15	0.00	0.04	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	0.07	0.00	0.00	0.55	0.00	0.00	0 00	0.00	0.00	0.00	0.00
EUOR	0.00	1.00	0.00	0.28	0.47	0.00	0.00	3.95	6.60	0.92	0 00	2.60	0.00	0.00	0.00
EUOF	0.00	0.95	0.00	0.28	0.47	0.00	0.00	3.54	2.71	0.65	0 00	0.94	0.00	0.00	0.00
POF	56.53	4.52	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	43.47	94.52	100 00	99.72	99.53	100.00	100.00	96.46	97.29	99.35	100 00	99.06	100.00	100.00	100.00

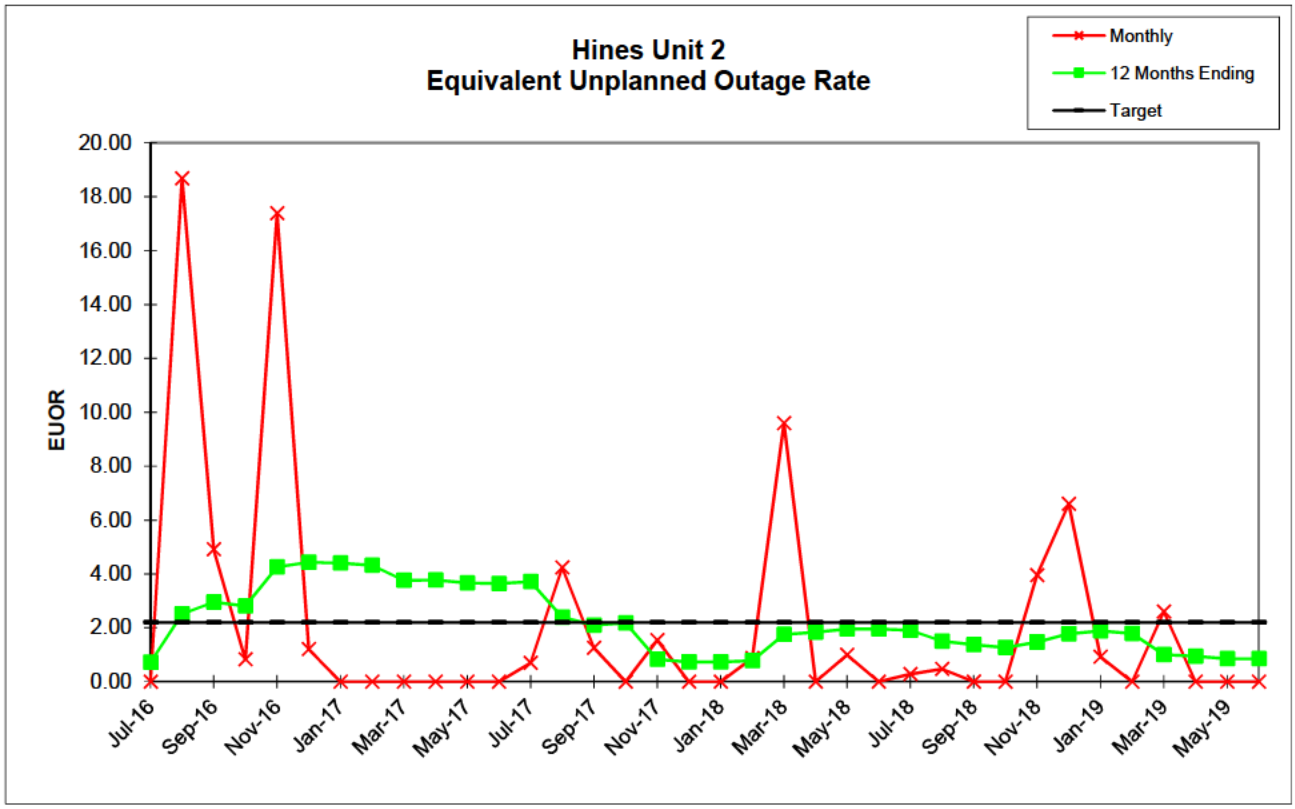
12 MONTHS	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**
FOR	1.60	1.69	1.69	1.72	1.37	1.27	1.17	1.07	1.37	1.47	1 39	0.47	0.45	0.36	0.36
MOR	0.08	0.08	0.08	0.00	0.04	0.04	0.04	0.33	0.34	0.35	0 34	0.46	0.44	0.43	0.43
PFOR	0.17	0.19	0.19	0.19	0.09	0.06	0.05	0.03	0.03	0.03	0 02	0.02	0.02	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.05	0.05	0.06	0 05	0.06	0.05	0.05	0.05
EUOR	1.84	1.95	1.95	1.91	1.50	1.37	1.27	1.47	1.78	1.88	1 80	1.00	0.95	0.85	0.85
EUOF	1.47	1.55	1.55	1.51	1.19	1.12	1.12	1.29	1.52	1.58	1 53	0.80	0.80	0.72	0.72
POF	12.57	12.96	12 96	12.96	12.96	10.74	5.03	5.03	5.03	5.03	5 03	5.03	0.38	0.00	0.00
EAF	85.96	85.49	85.49	85.53	85.85	88.14	93.85	93.68	93.45	93.39	93.44	94.17	98.81	99.28	99.28

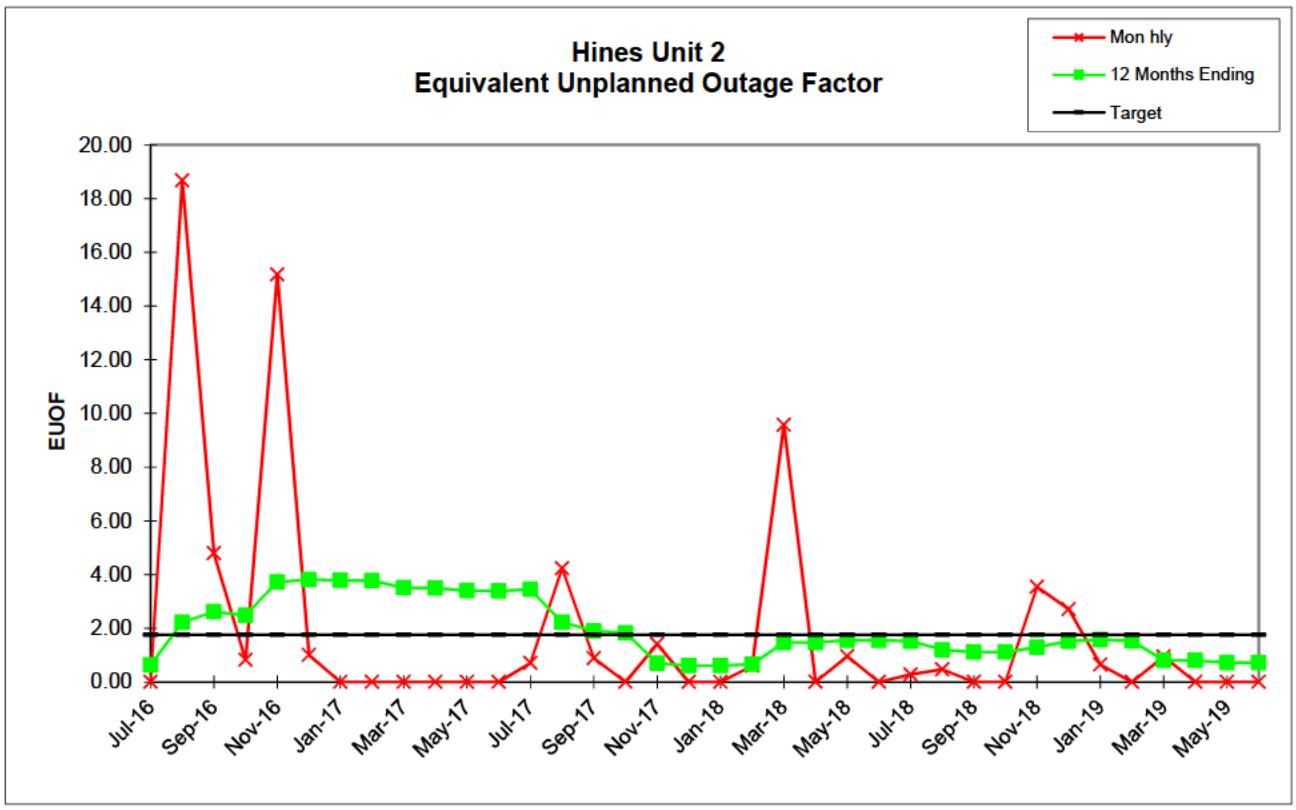

Hines Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 2
Partial Maintenance Outage Rate
Mon hly
12 Months Ending
Target
PMOR
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 2
Equivalent Unplanned Outage Factor
Mon hly
12 Months Ending
Target
EUOF
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
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Nov-17
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May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19

Hines
Unit 3

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18
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	744 00	672.00	743.00
SER HOURS	744.00	734.51	720.00	618.00	554.58	703.30	419.27	606.69	92.94	694.72	712 01	620.74	701.00	744.00	548.72	744.00	597.58	732.16	478.31	413.24	598.18
RSH	0.00	0.00	0.00	26.52	9.92	29.56	304.88	65.31	7.90	25.28	31 25	0.00	0.00	0.00	0.00	0.00	88.09	0.17	262 50	256.47	135.86
UH	0.00	9.49	0.00	99.47	156.50	11.14	19.85	0.00	642.16	0.00	0.74	99.26	43.00	0.00	171.28	0.00	35.33	11.66	3.18	2.28	8.96
POH	0.00	0.00	0.00	76.21	144.78	0.00	0.00	0.00	628.95	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	9.49	0.00	17.74	11.71	5.48	0.08	0.00	13.21	0.00	0.74	99.26	0.00	0.00	171.28	0.00	5.37	11.66	3.18	2.28	0.84
MOH	0.00	0.00	0.00	5.53	0.00	5.66	19.77	0.00	0.00	0.00	0.00	0.00	43.00	0.00	0.00	0.00	29.95	0.00	0 00	0.00	8.11
PFOH	0.00	0.00	0.00	0.00	0.00	7.05	0.09	0.00	0.00	0.00	0 00	0.00	0.00	0.00	137.97	0.00	0.00	6.22	2 94	1.11	0.98
LRPF	0.00	0.00	0.00	0.00	0.00	111.45	111.56	0.00	0.00	0.00	0 00	0.00	0.00	0.00	111.06	0.00	0.00	112.04	81 03	80.98	81.33
EFOH	0.00	0.00	0.00	0.00	0.00	1.44	0.02	0.00	0.00	0.00	0 00	0.00	0.00	0.00	28.22	0.00	0.00	1.28	0.46	0.17	0.15
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	22.68	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	19.34	0.00	0.00	0.00	7.93
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	110.04	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	108.08	0.00	0 00	0.00	82.96
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	4.60	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	3.85	0.00	0 00	0.00	1.26
NPC	544.00	544.00	544.00	544.00	544.00	544.00	543.00	543.00	543.00	543.00	543 00	543.00	543.00	543.00	543.00	543.00	543.00	543.00	521.00	521.00	521.00

MONTHLY	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**
FOR	0.00	1.28	0.00	2.79	2.07	0.77	0.02	0.00	12.44	0.00	0.10	13.79	0.00	0.00	23.79	0.00	0.89	1.57	0.66	0.55	0.14
MOR	0.00	0.00	0.00	0.89	0.00	0.80	4.50	0.00	0.00	0.00	0 00	0.00	5.78	0.00	0.00	0.00	4.77	0.00	0 00	0.00	1.34
PFOR	0.00	0.00	0.00	0.00	0.00	0.21	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	5.14	0.00	0.00	0.18	0.10	0.04	0.03
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	1.10	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.64	0.00	0 00	0.00	0.21
EUOR	0.00	1.28	0.00	3.63	2.07	1.76	5.57	0.00	12.44	0.00	0.10	13.79	5.78	0.00	27.71	0.00	6.19	1.74	0.76	0.59	1.71
EUOF	0.00	1.28	0.00	3.13	1.62	1.69	3.29	0.00	1.78	0.00	0.10	13.79	5.78	0.00	27.71	0.00	5.43	1.74	0.49	0.36	1.40
POF	0.00	0.00	0.00	10.24	20.08	0.00	0.00	0.00	84.65	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	98.72	100.00	86.63	78.30	98.31	96.71	100.00	13.57	100.00	99 90	86.21	94.22	100.00	72.29	100.00	94.57	98.26	99 51	99.64	98.60

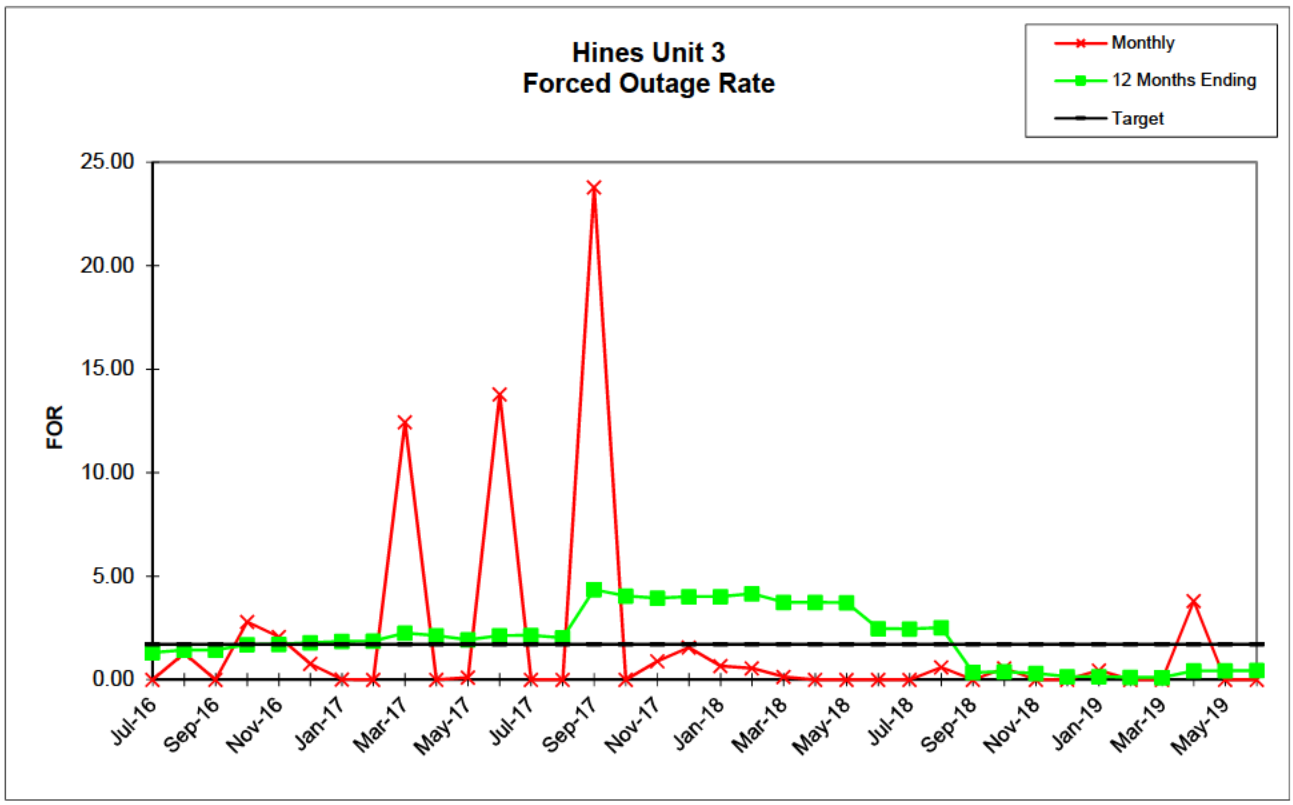
12 MONTHS	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**
FOR	1.32	1.44	1.44	1.70	1.72	1.79	1.86	1.87	2.26	2.14	1 94	2.14	2.15	2.02	4.36	4.05	3.95	4.01	4 02	4.16	3.74
MOR	0.26	0.26	0.21	0.29	0.30	0.38	0.68	0.68	0.75	0.49	0.44	0.43	1.02	1.02	1.04	0.95	1.35	1.27	0 99	1.02	1.06
PFOR	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0 02	0.02	0.02	0.02	0.42	0.42	0.41	0.41	0.41	0.43	0.40
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.07	0.07	0.07	0 07	0.06	0.06	0.06	0.07	0.06	0.12	0.12	0 05	0.05	0.07
EUOR	1.56	1.69	1.65	1.99	2.01	2.17	2.60	2.62	3.07	2.71	2.45	2.63	3.21	3.08	5.77	5.38	5.70	5.68	5 38	5.55	5.16
EUOF	1.33	1.44	1.40	1.66	1.65	1.79	2.07	2.08	2.23	1.99	1 99	2.22	2.71	2.61	4.88	4.62	4.93	4.93	4.70	4.73	4.69
POF	13.22	13.22	13.22	14.09	15.74	15.10	15.10	15.14	22.32	21.23	12.74	9.70	9.70	9.70	9.70	8.83	7.18	7.18	7.18	7.18	0.00
EAF	85.45	85.34	85.38	84.25	82.61	83.11	82.83	82.78	75.45	76.78	85 27	88.07	87.58	87.69	85.41	86.55	87.89	87.89	88.12	88.10	95.31

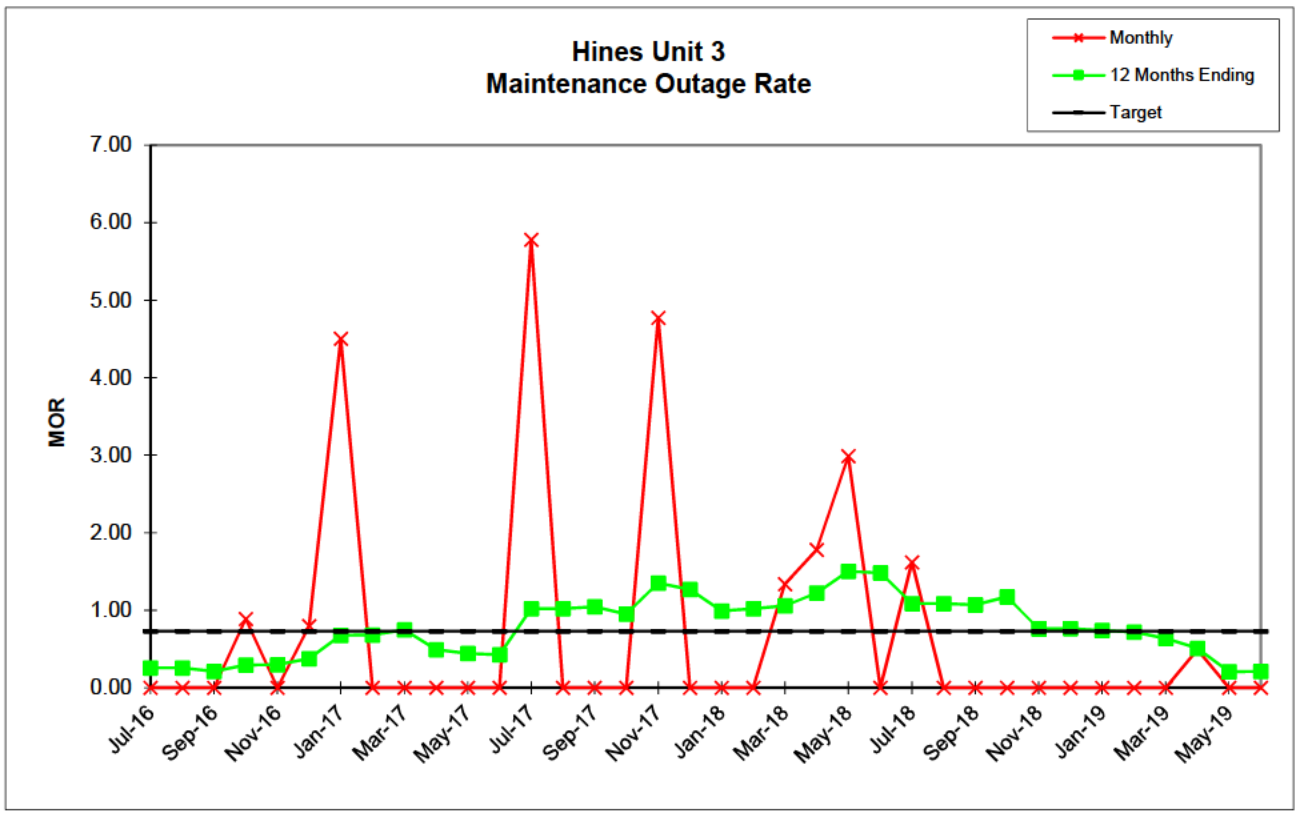
Hines
Unit 3

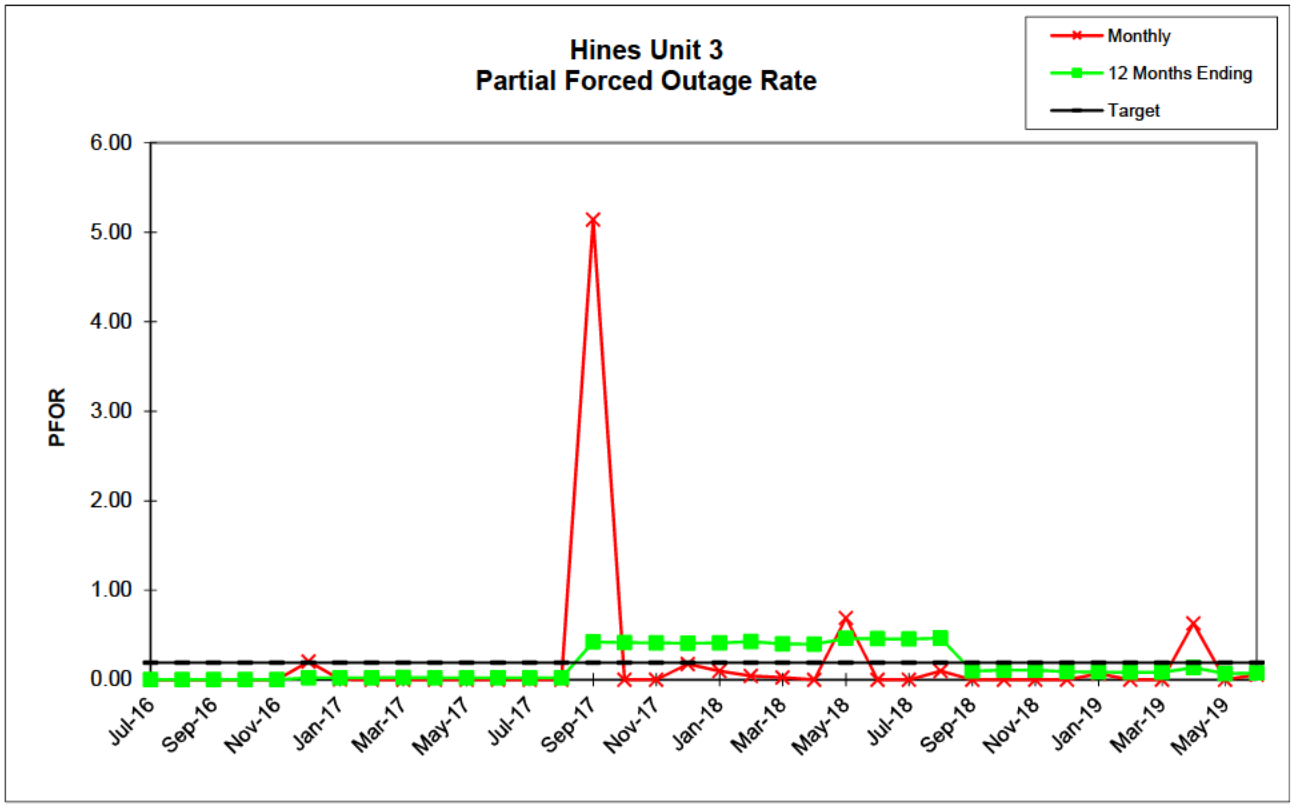
	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
PER HOURS	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672 00	743.00	720.00	744.00	720.00
SER HOURS	705.76	710.57	720.00	731.95	739.49	673.52	39.01	605.99	706.70	700.11	638 34	343.61	606.56	744.00	604.15
RSH	1.44	11.55	0.00	0.00	0.00	0.00	0.00	113.58	37.30	40.69	33.66	399.39	86.52	0.00	115.85
UH	12.80	21.89	0.00	12.05	4.51	46.48	704.99	1.43	0.00	3.20	0 00	0.00	26.93	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	46.48	704.77	1.43	0.00	0.00	0 00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	4.51	0.00	0.22	0.00	0.00	3.20	0 00	0.00	23.93	0.00	0.00
MOH	12.80	21.89	0.00	12.05	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	3.00	0.00	0.00
PFOH	0.00	39.40	0.00	0.00	4.40	0.00	0.00	0.00	0.00	3.28	0 00	0.00	24.53	0.00	3.68
LRPF	0.00	64.74	0.00	0.00	86.01	0.00	0.00	0.00	0.00	75.32	0 00	0.00	80.41	0.00	49.58
EFOH	0.00	4.90	0.00	0.00	0.73	0.00	0.00	0.00	0.00	0.48	0 00	0.00	3.82	0.00	0.35
PMOH	12.50	9.07	0.00	11.77	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00
LRPM	81.65	83.99	0.00	87.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00
EMOH	1.96	1.46	0.00	1.97	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	521.00	521.00	521.00	516.00	516 00	516.00	516.00	516.00	516.00

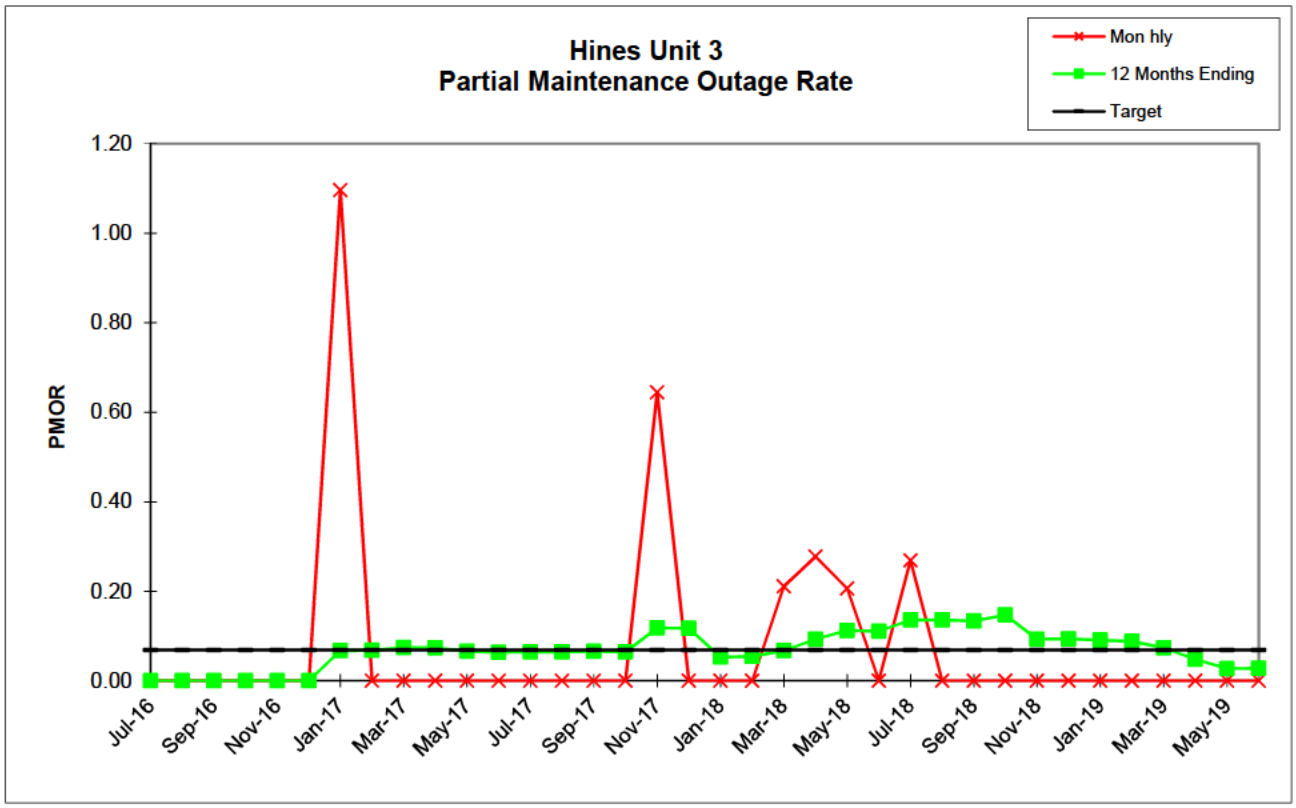
MONTHLY	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**
FOR	0.00	0.00	0.00	0.00	0.61	0.00	0.56	0.00	0.00	0.45	0 00	0.00	3.80	0.00	0.00
MOR	1.78	2.99	0.00	1.62	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.49	0.00	0.00
PFOR	0.00	0.69	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.07	0 00	0.00	0.63	0.00	0.06
PMOR	0.28	0.21	0.00	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00
EUOR	2.05	3.86	0.00	1.88	0.70	0.00	0.56	0.00	0.00	0.52	0 00	0.00	4.85	0.00	0.06
EUOF	2.05	3.80	0.00	1.88	0.70	0.00	0.03	0.00	0.00	0.49	0 00	0.00	4.27	0.00	0.05
POF	0.00	0.00	0.00	0.00	0.00	6.46	94.73	0.20	0.00	0.00	0 00	0.00	0.00	0.00	0.00
EAF	97.95	96.20	100 00	98.12	99.30	93.54	5.24	99.80	100.00	99.51	100 00	100.00	95.73	100.00	99.95

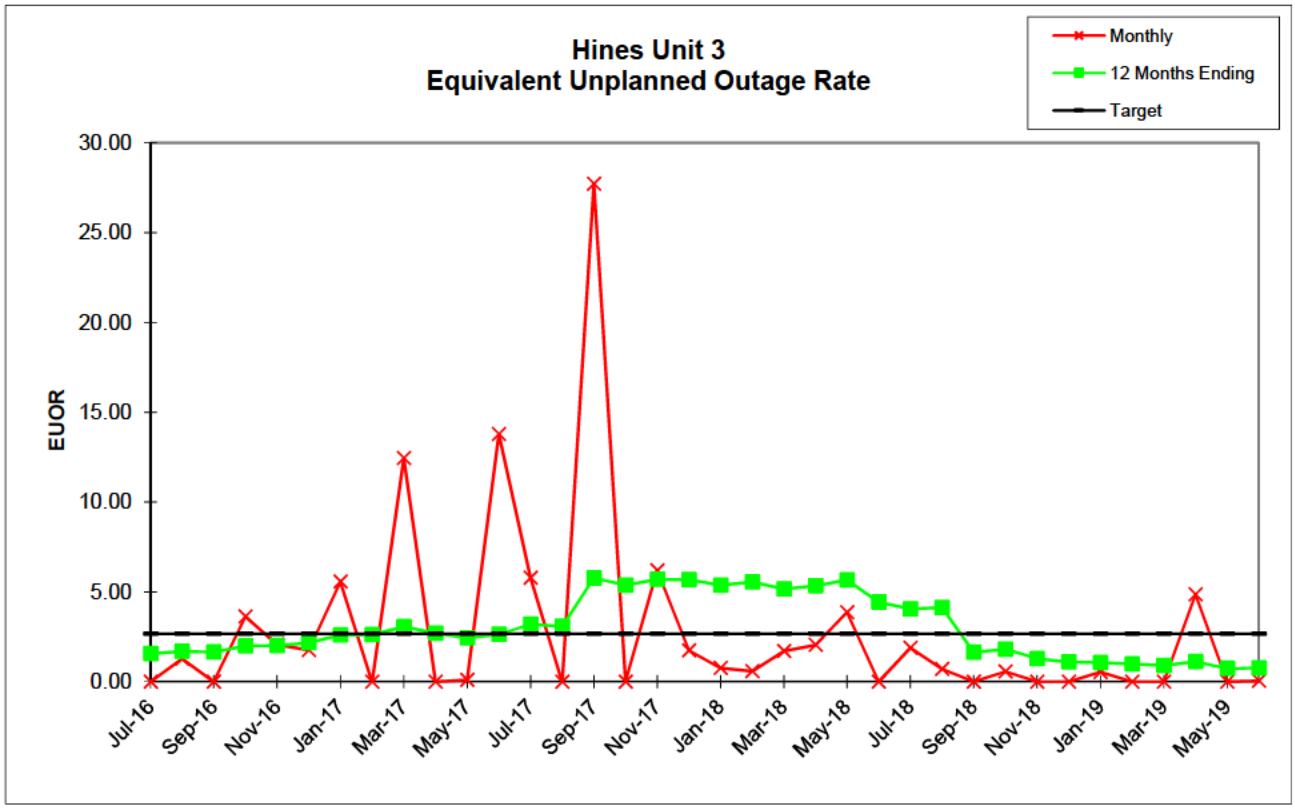
12 MONTHS	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**
FOR	3.73	3.73	2.47	2.46	2.51	0.35	0.39	0.32	0.15	0.15	0.12	0.11	0.44	0.44	0.44
MOR	1.22	1.50	1.48	1.09	1.09	1.07	1.17	0.76	0.76	0.74	0.72	0.63	0.51	0.21	0.21
PFOR	0.40	0.46	0.46	0.46	0.47	0.10	0.11	0.11	0.09	0.09	0 08	0.08	0.14	0.07	0.08
PMOR	0.09	0.11	0.11	0.14	0.14	0.13	0.15	0.09	0.09	0.09	0 09	0.07	0.05	0.03	0.03
EUOR	5.33	5.66	4.42	4.06	4.13	1.64	1.81	1.27	1.10	1.07	1 00	0.90	1.13	0.74	0.76
EUOF	4.86	5.18	4.04	3.71	3.77	1.49	1.50	1.05	0.90	0.90	0 87	0.76	0.94	0.62	0.62
POF	0.00	0.00	0.00	0.00	0.00	0.53	8.58	8.59	8.59	8.59	8 59	8.59	8.59	8.59	8.59
EAF	95.14	94.82	95.96	96.29	96.23	97.98	89.93	90.36	90.51	90.51	90 53	90.65	90.47	90.79	90.79

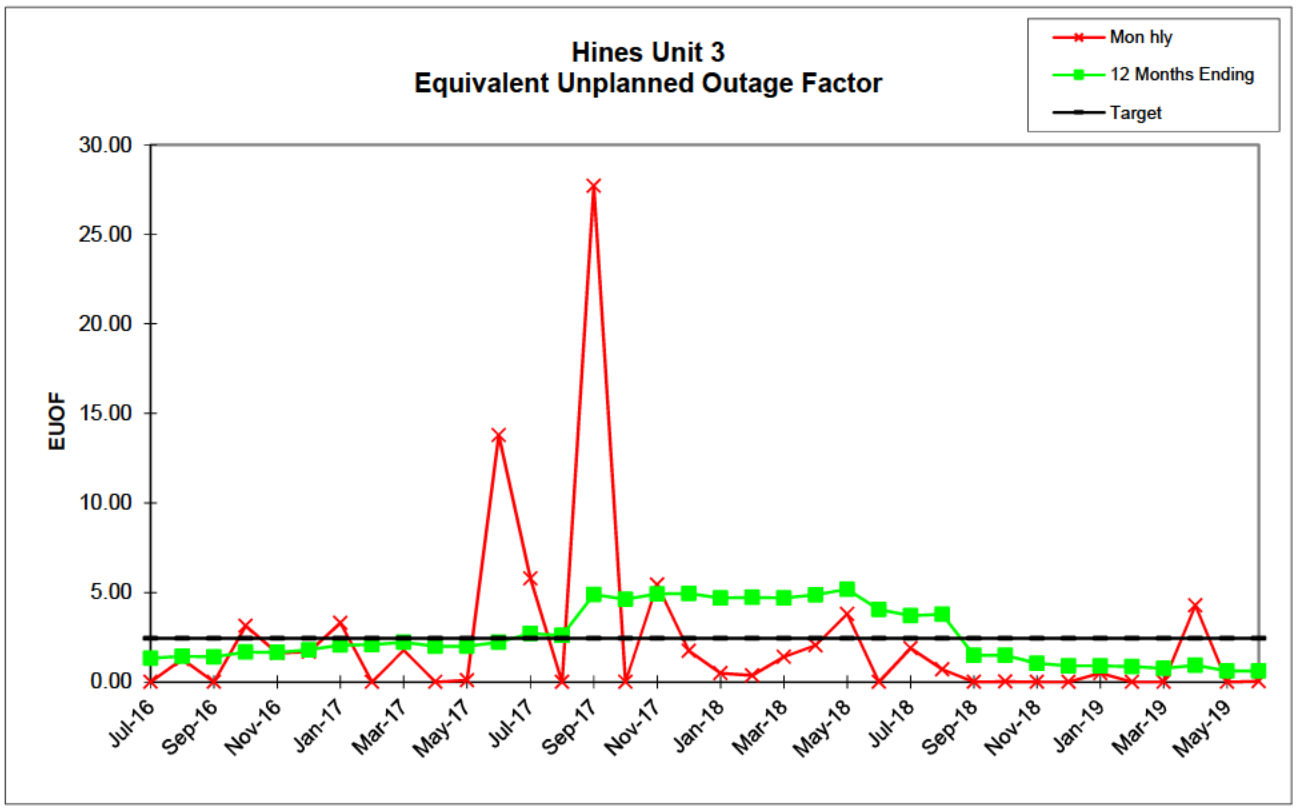

Hines Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 3
Partial Maintenance Outage Rate
Mon hly
12 Months Ending
Target
PMOR
1.20
1.00
0.80
0.60
0.40
0.20
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 3
Equivalent Unplanned Outage Factor
Mon hly
12 Months Ending
Target
EUOF
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
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May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19

Hines
Unit 4

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
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	0.00	167.28	720.00	574.12	440.25	404.42	627.78	522 95	743.00	693.40	696.30	683.45	675.38	708.20	711.67	741.07	212.06	377.19
RSH	0.00	0.00	0.00	38.63	9.60	2 84	116.22	148 30	0.00	0.00	36.82	18.81	9.16	2.29	8.33	0.00	18.28	78.42
UH	744.00	576.72	0.00	131.25	271.15	336.74	0.00	0.75	0.00	26.60	10.88	17.74	59.46	33.51	0.00	2.93	490.66	288.39
POH	0.00	0.00	0.00	130.53	230.12	320 04	0.00	0 00	0.00	13.83	0.00	0.00	0.00	0.00	0.00	0.00	489.55	288.39
FOH	744.00	576.72	0.00	0.73	0.32	0.00	0.00	0.75	0.00	12.76	10.88	2.72	50.46	33.51	0.00	2.93	1.11	0.00
MOH	0.00	0.00	0.00	0.00	40.71	16.70	0.00	0 00	0.00	0.00	0.00	15.02	9.01	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0 84	0.00	0.00	12.25	50.05	171.67	20.32	0.00	3.30	1.25	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0 00	0.00	106 85	0.00	0.00	119.76	70.27	74.14	67.81	0.00	87.68	99.69	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.17	0.00	0.00	2.78	6.67	24.15	2.61	0.00	0.55	0.24	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	528.00	528.00	528.00	528.00	528.00	528.00	527.00	527 00	527.00	527.00	527.00	527.00	527.00	527.00	527.00	527.00	527.00	527.00

MONTHLY	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
FOR	100.00	77.52	0.00	0.13	0.07	0 00	0.00	0.14	0.00	1.81	1.54	0.40	6.95	4.52	0.00	0.39	0.52	0.00
MOR	0.00	0.00	0.00	0.00	8.46	3.97	0.00	0 00	0.00	0.00	0.00	2.15	1.32	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0 03	0.00	0.00	0.40	0.98	3.58	0.37	0.00	0.07	0.11	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	100.00	77.52	0.00	0.13	8.53	3 97	0.00	0.18	0.00	1.81	1.93	3.48	11.38	4.87	0.00	0.47	0.63	0.00
EUOF	100.00	77.52	0.00	0.10	5.69	2 24	0.00	0.14	0.00	1.77	1.84	3.39	11.24	4.86	0.00	0.47	0.19	0.00
POF	0.00	0.00	0.00	17.54	31.92	43 02	0.00	0 00	0.00	1.92	0.00	0.00	0.00	0.00	0.00	0.00	67.90	38.76
EAF	0.00	22.48	100.00	82.36	62.39	54.74	100.00	99 86	100.00	96.31	98.16	96.61	88.76	95.14	100.00	99.53	31.91	61.24

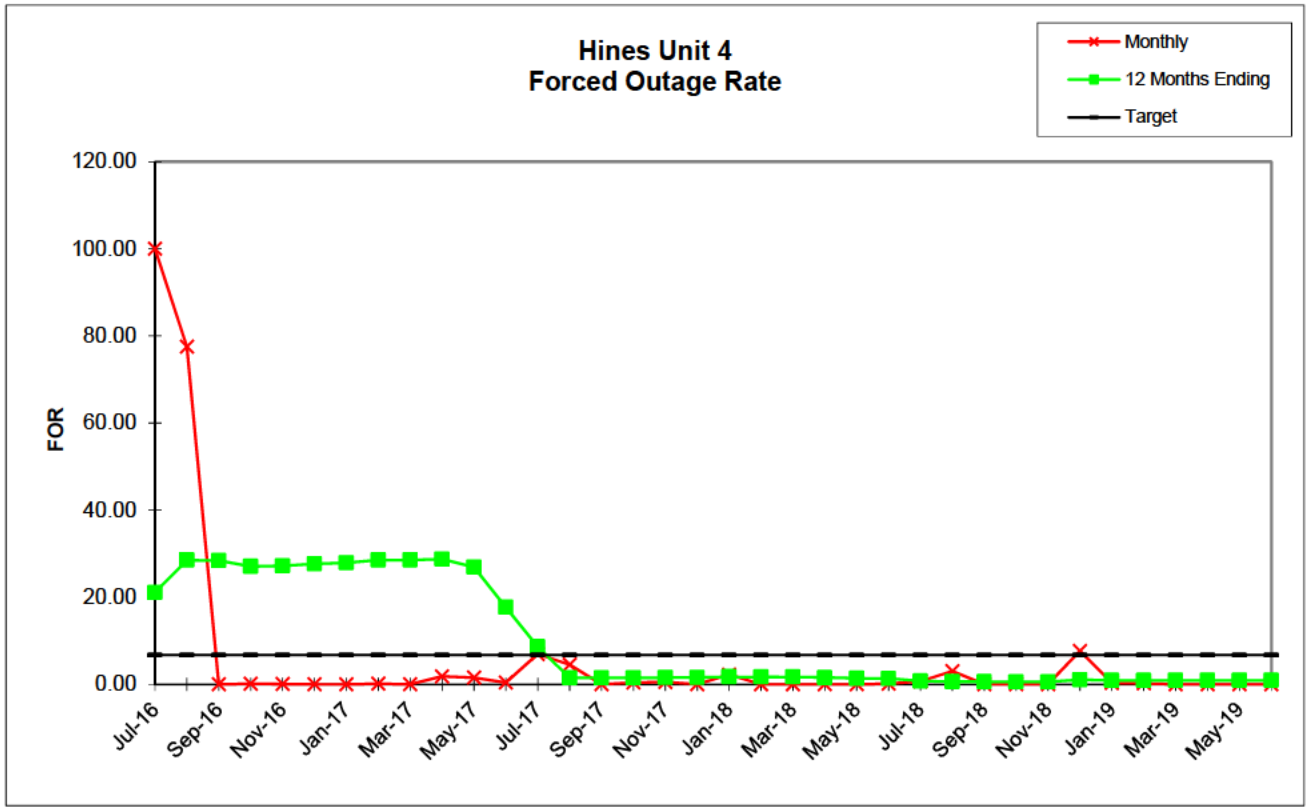
12 MONTHS	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
FOR	21.06	28.51	28.41	27.07	27.20	27.65	27.90	28 53	28.53	28.75	26.91	17.70	8.62	1.48	1.48	1.47	1.53	1.53
MOR	0.28	0.31	0.31	0.29	0.97	1 28	1.30	1 34	1.34	1.35	1.02	1.14	1.16	1.08	1.08	1.05	0.55	0.32
PFOR	0.37	0.41	0.41	0.38	0.39	0.40	0.40	0.42	0.42	0.42	0.05	0.15	0.49	0.49	0.49	0.48	0.50	0.50
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	21.54	28.96	28.86	27.50	28.00	28.61	28.86	29 51	29.51	29.73	27.49	18.60	10.03	2.99	3.00	2.97	2.55	2.34
EUOF	19.04	25.61	25.61	25.62	26.08	26.15	26.08	26.16	26.16	26.30	24.21	16.33	8.80	2.63	2.63	2.66	2.20	2.01
POF	10.65	10.65	10.65	5.81	5.80	7.75	7.75	7.77	7.77	7.93	7.93	7.93	7.93	7.93	7.93	6.44	9.40	9.04
EAF	70.31	63.74	63.74	68.58	68.12	66.10	66.17	66 07	66.07	65.77	67.87	75.74	83.28	89.45	89.45	90.91	88.40	88.95

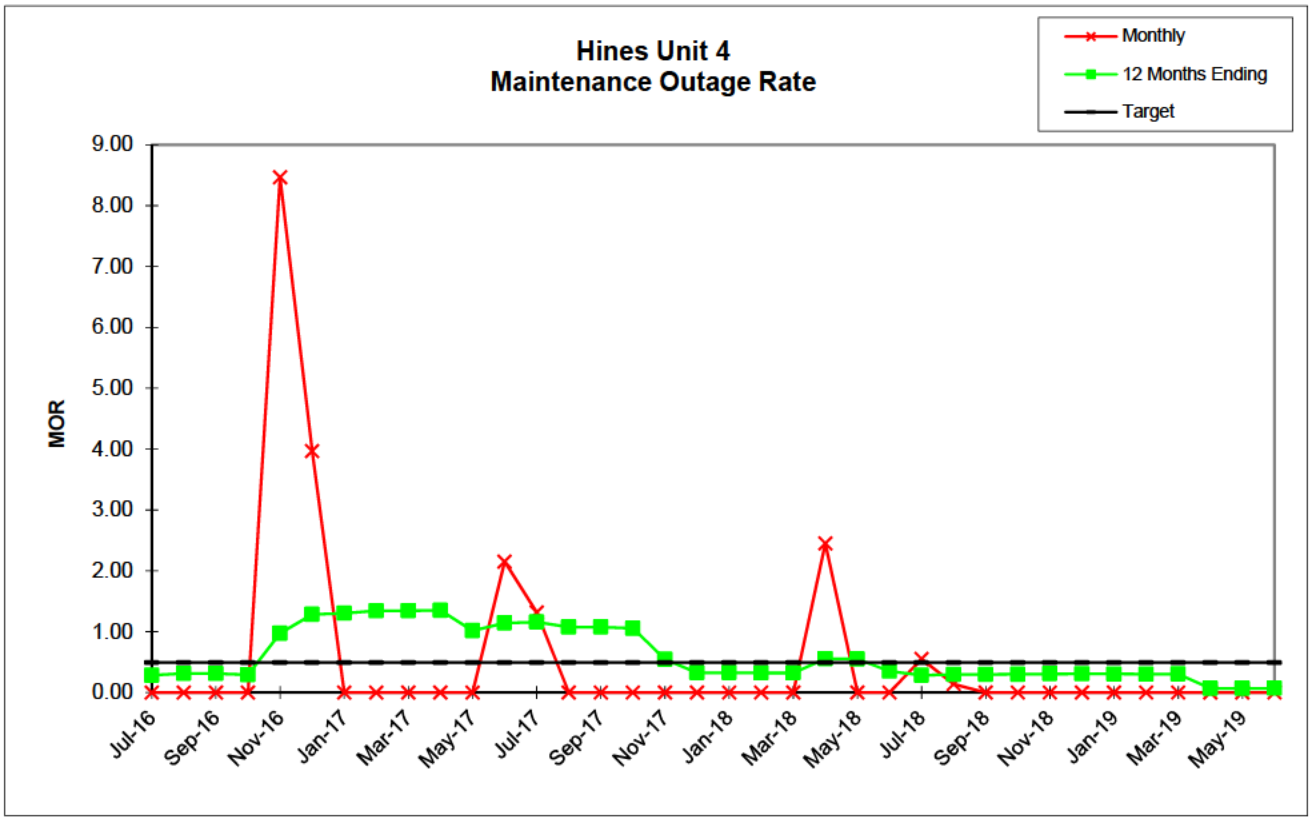
Hines
Unit 4

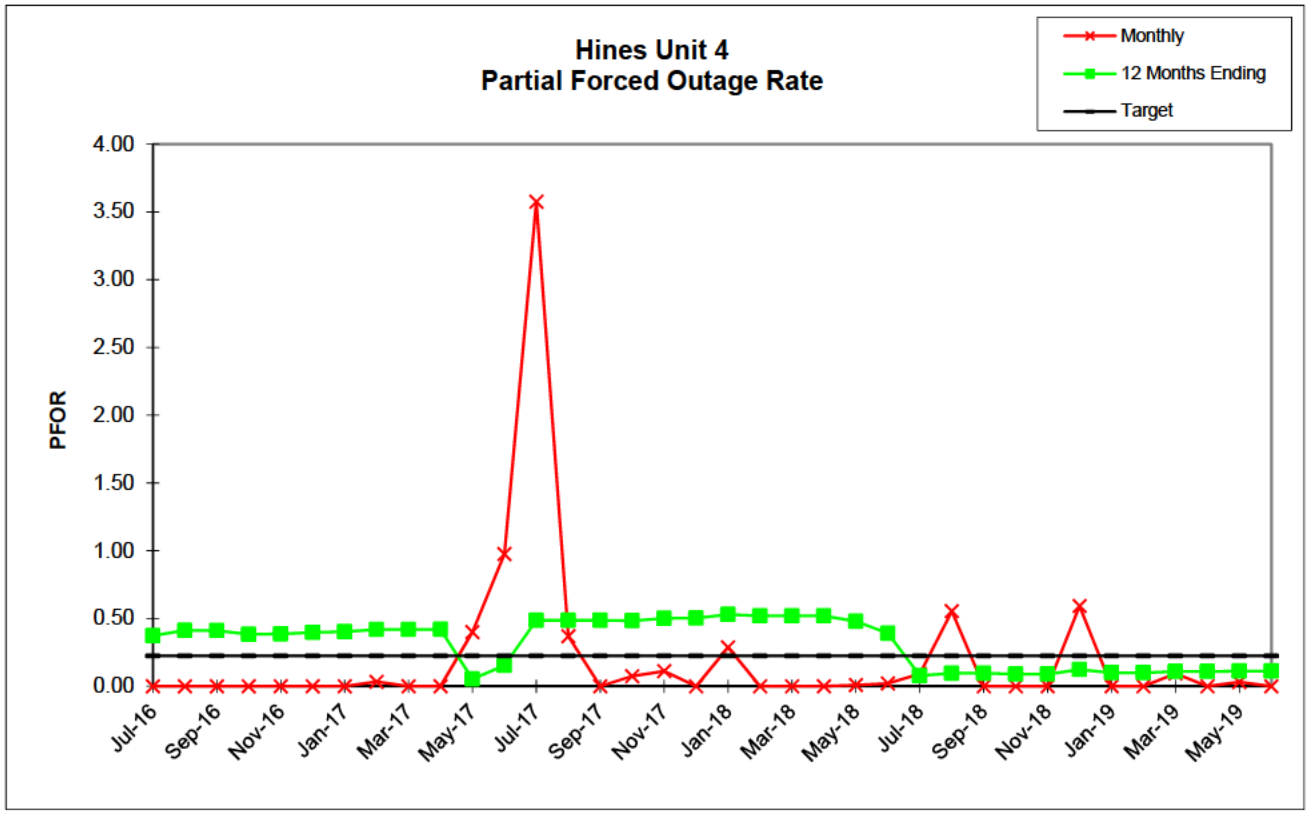
	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744 00	720.00	744 00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	574.23	630.03	743.00	697.74	744.00	718.97	734.94	715 29	720.00	640.18	0.00	436.62	677.19	637.21	680.19	678.23	738.92	603.62
RSH	156.80	41.97	0.00	4.75	0.00	0.00	0.00	5.44	0.00	103.82	328.02	76.72	64.80	33.43	62.81	41.77	5.08	116.38
UH	12.97	0.00	0.00	17.52	0.00	1.03	9.06	23 27	0.00	0.00	392.98	230.66	2.01	1.35	0.00	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	0.00	392.98	194.46	0.00	0.00	0.00	0.00	0.00	0.00
FOH	12.97	0.00	0.00	0.00	0.00	1.03	4.99	22 28	0.00	0.00	0.00	36.20	2.01	1.35	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	17.52	0.00	0.00	4.07	0 99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	11.99	0.00	0.00	0.00	0.58	0.97	4.71	57 32	0.00	0.00	0.00	19.40	0.00	0.00	8.50	0.00	2.11	0.00
LRPF	69.17	0.00	0.00	0.00	54.26	76.15	71.10	34 84	0.00	0.00	0.00	67.16	0.00	0.00	38.73	0.00	55.13	0.00
EFOH	1.65	0.00	0.00	0.00	0.06	0.15	0.66	3 96	0.00	0.00	0.00	2.59	0.00	0.00	0.64	0.00	0.23	0.00
PMOH	0.00	0.00	0.00	16.52	0.00	0.00	3.84	0 00	0.00	0.00	0.00	0.00	0.00	1.30	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	78.14	0.00	0.00	79.10	0 00	0.00	0.00	0.00	0.00	0.00	78.08	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	2.56	0.00	0.00	0.60	0 00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.00	0.00
NPC	504.00	504.00	504.00	504.00	504.00	504.00	504.00	504 00	504.00	504 00	504.00	504.00	516.00	516.00	516.00	516.00	516.00	516.00

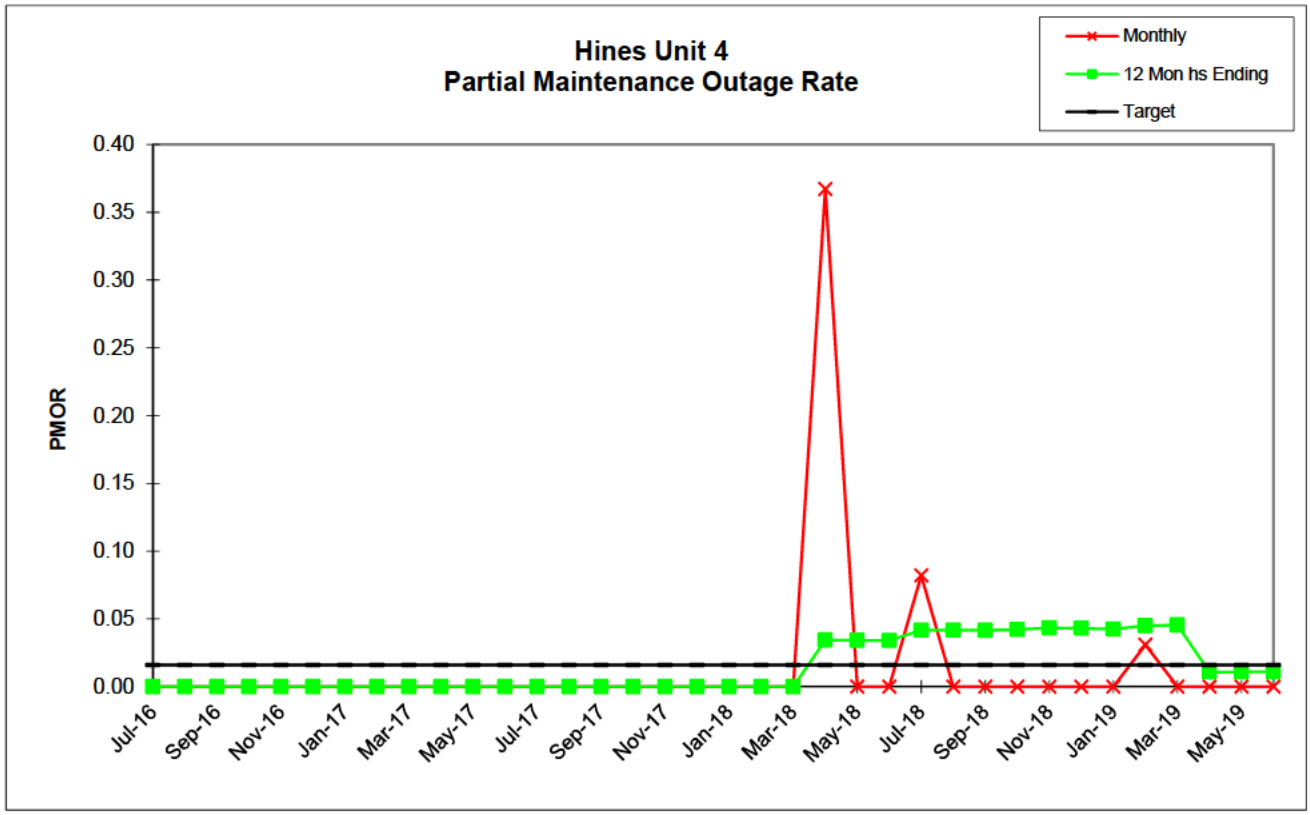
MONTHLY	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**
FOR	2.21	0.00	0.00	0.00	0.00	0.14	0.67	3 02	0.00	0.00	0.00	7.66	0.30	0.21	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	2.45	0.00	0.00	0.55	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.29	0.00	0.00	0.00	0.01	0.02	0.09	0 55	0.00	0.00	0.00	0.59	0.00	0.00	0.09	0.00	0.03	0.00
PMOR	0.00	0.00	0.00	0.37	0.00	0.00	0.08	0 00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00
EUOR	2.49	0.00	0.00	2.81	0.01	0.16	1.39	3.69	0.00	0.00	0.00	8.20	0.30	0.24	0.09	0.00	0.03	0.00
EUOF	1.96	0.00	0.00	2.79	0.01	0.16	1.39	3.66	0.00	0.00	0.00	5.21	0.27	0.23	0.09	0.00	0.03	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	54.50	26.14	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.04	100.00	100.00	97.21	99.99	99.84	98.61	96 34	100.00	100 00	45.50	68.65	99.73	99.77	99.91	100.00	99.97	100.00

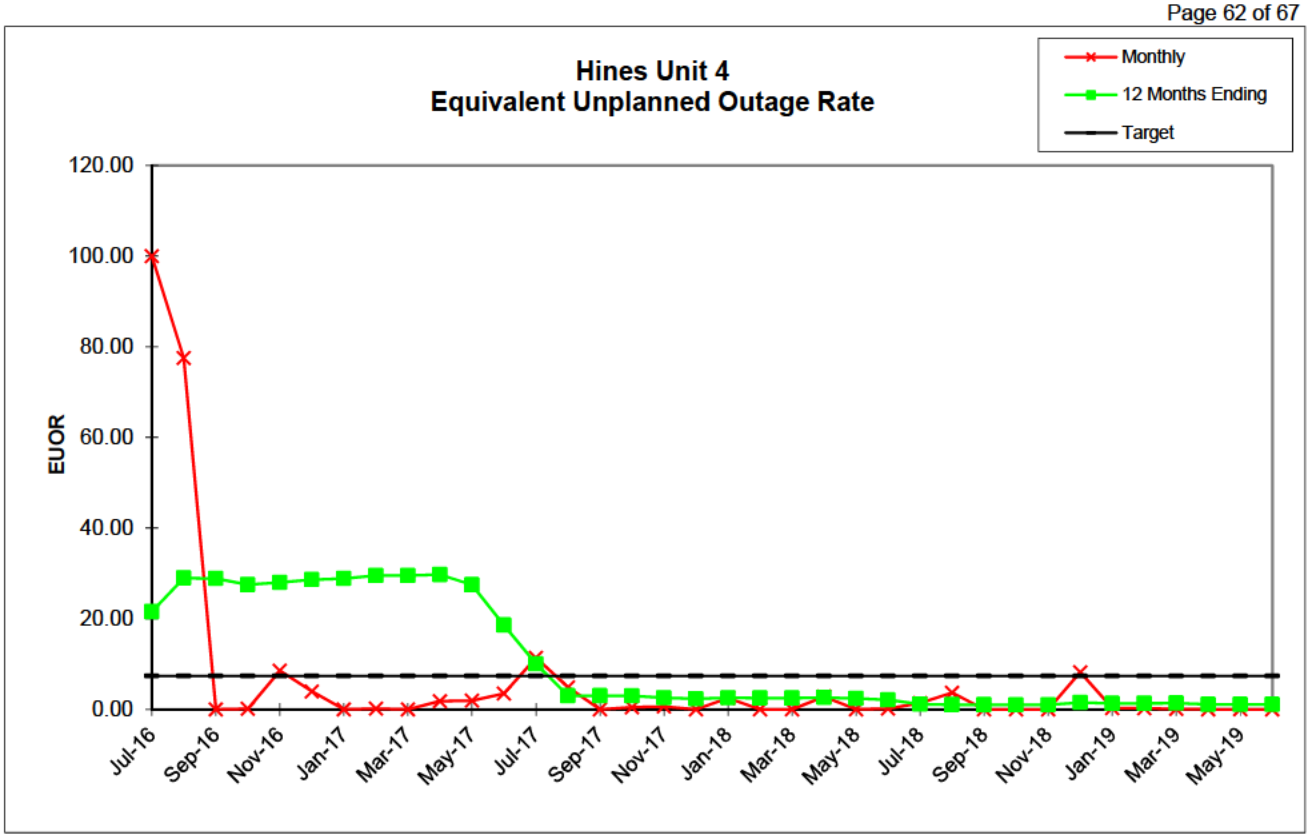
12 MONTHS	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**
FOR	1.72	1.68	1.68	1.51	1.36	1.34	0.74	0 59	0.59	0.56	0.56	1.04	0.88	0.90	0.91	0.91	0.91	0.91
MOR	0.33	0.32	0.32	0.55	0.55	0.35	0.28	0 30	0.30	0.30	0.31	0.31	0.30	0.30	0.30	0.07	0.07	0.07
PFOR	0.53	0.52	0.52	0.52	0.48	0.39	0.08	0.10	0.10	0.09	0.09	0.12	0.10	0.10	0.11	0.11	0.11	0.11
PMOR	0.00	0.00	0.00	0.03	0.03	0.03	0.04	0 04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.01	0.01	0.01
EUOR	2.55	2.50	2.50	2.59	2.40	2.09	1.14	1 02	1.02	0.99	1.00	1.51	1.32	1.34	1.36	1.10	1.10	1.10
EUOF	2.18	2.17	2.17	2.25	2.10	1.83	1.00	0 89	0.89	0.85	0.84	1.28	1.14	1.16	1.16	0.93	0.94	0.92
POF	9.04	9.04	9.04	8.88	8.88	8.88	8.88	8 88	8.88	8.88	7.78	6.71	6.71	6.71	6.71	6.71	6.71	6.71
EAF	88.78	88.79	88.79	88.87	89.02	89.29	90.12	90 23	90.23	90 27	91.38	92.01	92.16	92.14	92.13	92.36	92.36	92.37

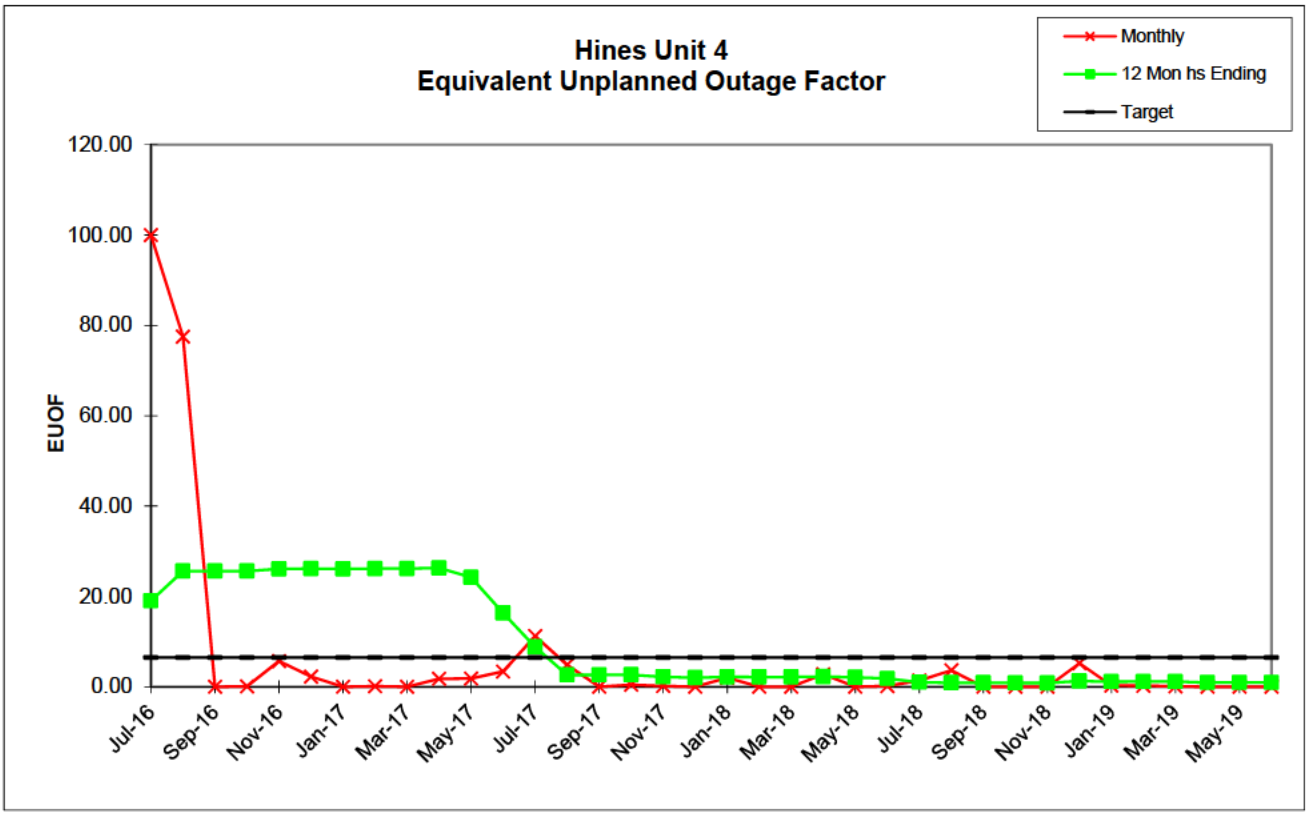

Hines Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 4
Partial Maintenance Outage Rate
Monthly
12 Mon hs Ending
Target
PMOR
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Hines Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Mon hs Ending
Target
EUOF
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
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Jan-18
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May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19

Osprey
Unit 1

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18
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	744.00	672.00
SER HOURS	737.09	738.18	306.45	511.12	687.62	318.39	91.66	278.65	0.00	0.00	0.00	214 01	703.64	742.09	317.77	584.35	490.27	647.65	433.99	9.85
RSH	1.91	1.58	76 27	113.02	33.38	414.30	652.34	297.41	0.00	0.00	0.00	17 50	39.30	1.91	116.83	159.65	228.04	96.35	259.88	542.15
UH	5.00	4.24	337 27	119.86	0.00	11.31	0.00	95.94	743.00	720.00	744.00	488.49	1.06	0.00	285.40	0.00	2.69	0.00	50.13	120.00
POH	0.00	0.00	335 86	113.57	0.00	0.00	0.00	95.94	743.00	720.00	744.00	488.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	120.00
FOH	5.00	0.00	1.41	0.18	0.00	11.31	0.00	0.00	0.00	0.00	0.00	0 06	1.06	0.00	13.71	0.00	2.69	0.00	50.13	0.00
MOH	0.00	4.24	0 00	6.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	271.69	0.00	0.00	0.00	0.00	0.00
PFOH	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	0.00	0.00
LRPF	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	0.00	0.00
EFOH	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	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	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	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	0.00	0.00
NPC	582.00	582.00	582 00	582.00	582.00	582.00	582.00	582.00	582.00	582.00	582.00	582 00	582.00	582.00	582.00	582.00	582.00	582.00	582.00	582.00

MONTHLY	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**
FOR	0.67	0.00	0.46	0.04	0.00	3.43	0.00	0.00	0.00	0.00	0.00	0 03	0.15	0.00	4.14	0.00	0.55	0.00	10.35	0.00
MOR	0.00	0.57	0 00	1.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	46.09	0.00	0.00	0.00	0.00	0.00
PFOR	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	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	0.00	0.00
EUOR	0.67	0.57	0.46	1.22	0.00	3.43	0.00	0.00	0.00	0.00	0.00	0 03	0.15	0.00	47.32	0.00	0.55	0.00	10.35	0.00
EUOF	0.67	0.57	0 20	0.85	0.00	1.52	0.00	0.00	0.00	0.00	0.00	0 01	0.14	0.00	39.64	0.00	0.37	0.00	6.74	0.00
POF	0.00	0.00	46.65	15.26	0.00	0.00	0.00	14.28	100.00	100.00	100.00	67.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.86
EAF	99.33	99.43	53.16	83.89	100.00	98.48	100.00	85.72	0.00	0.00	0.00	32.15	99.86	100.00	60.36	100.00	99.63	100.00	93.26	82.14

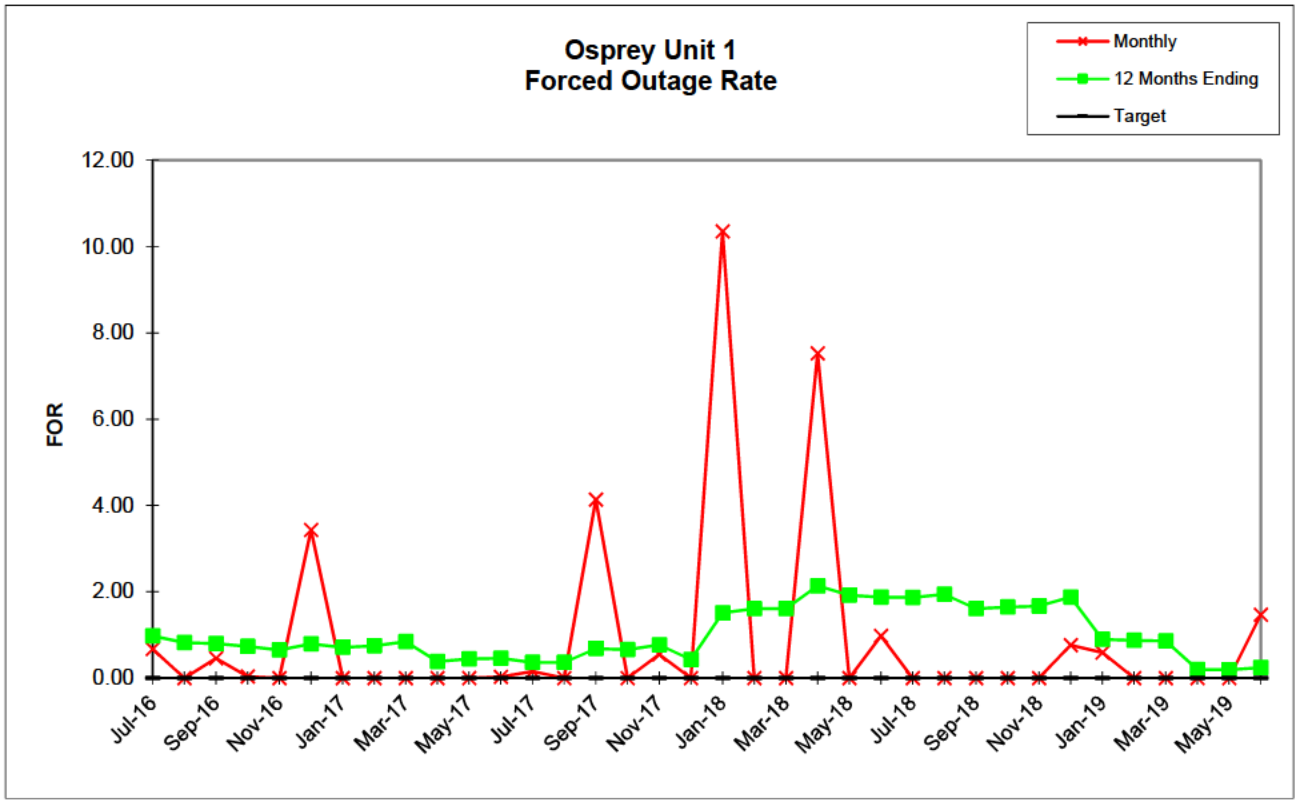
12 MONTHS	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**
FOR	0.97	0.82	0 80	0.73	0.65	0.79	0.71	0.75	0.84	0.38	0.44	0.46	0.36	0.36	0.68	0.66	0.76	0.43	1.51	1.61
MOR	1.11	1.03	0 97	0.99	0.88	0.83	0.85	0.84	0.94	0.99	0.24	0 27	0.27	0.16	6.71	6.45	6.77	6.26	5.80	6.15
PFOR	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	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	0.00	0.00
EUOR	2.07	1.83	1.75	1.70	1.51	1.61	1.55	1.58	1.77	1.36	0.67	0.72	0.63	0.52	7.29	7.03	7.44	6.63	7.14	7.57
EUOF	1.62	1.49	1 34	1.29	1.18	1.21	1.14	1.09	1.09	0.80	0.34	0 32	0.28	0.23	3.47	3.40	3.43	3.30	3.87	3.87
POF	10.63	9.28	13 37	13.56	12.34	11.30	11.30	12.43	19.80	22.93	31.42	37 00	37.00	37.00	33.16	31.86	31.86	31.86	31.86	32.14
EAF	87.76	89.24	85 29	85.15	86.48	87.49	87.56	86.48	79.10	76.27	68.24	62.68	62.73	62.77	63.37	64.74	64.70	64.83	64.26	63.99

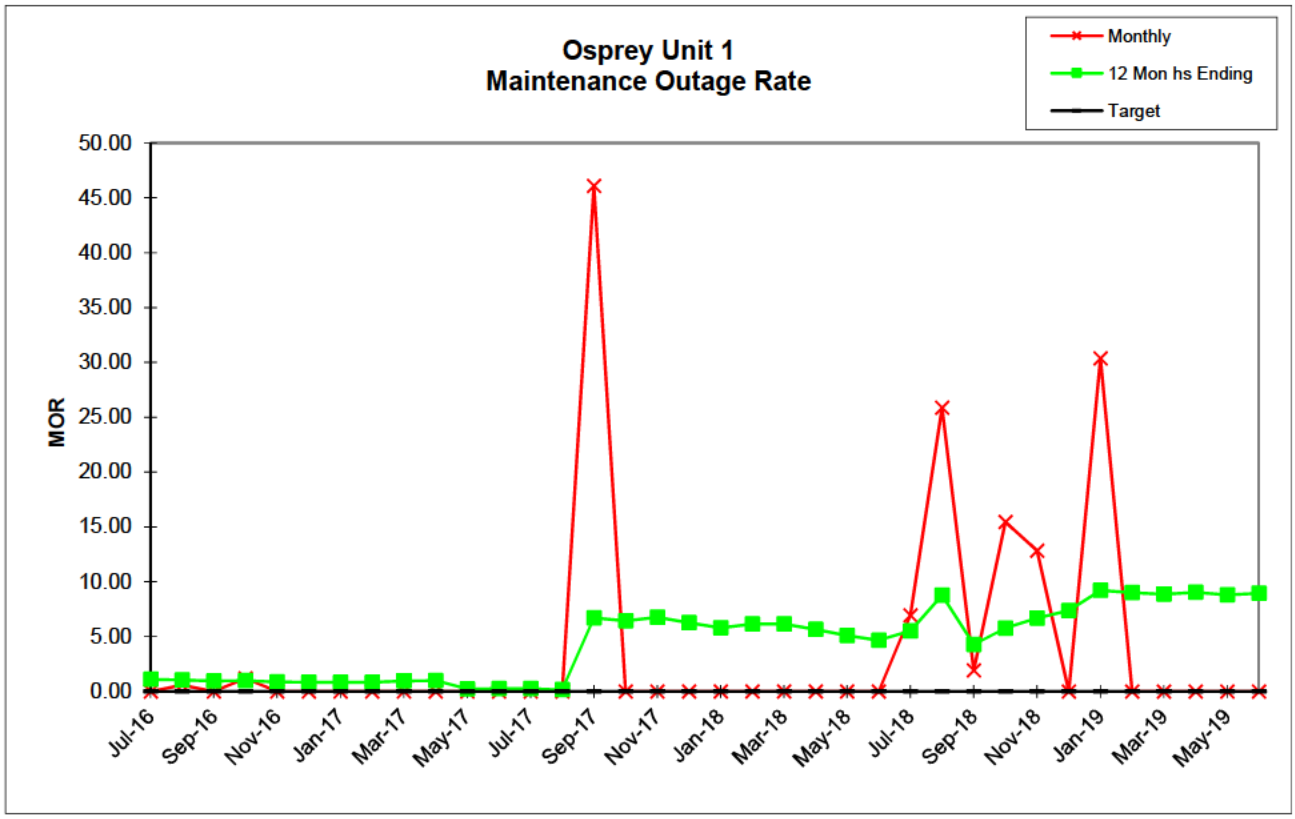
Osprey
Unit 1

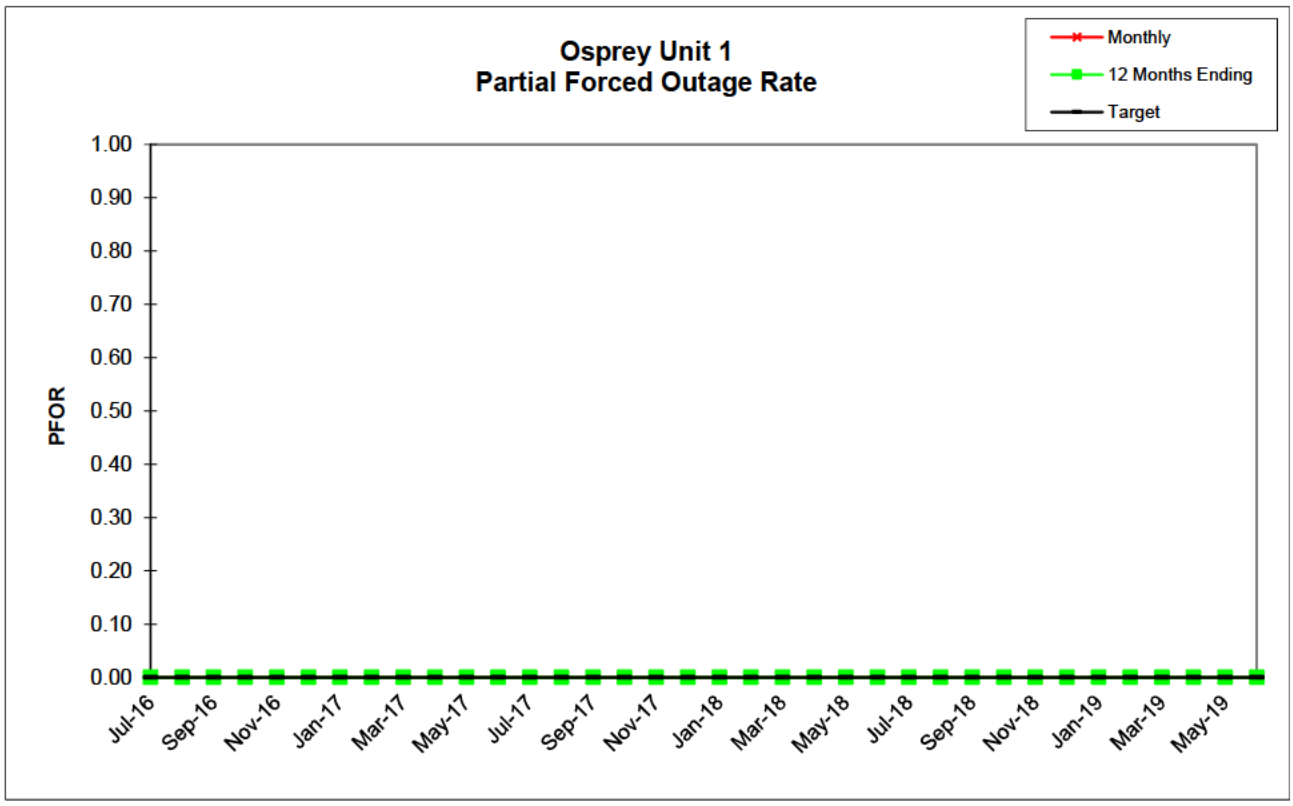
	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
PER HOURS	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744 00	672.00	743.00	720.00	744.00	720.00
SER HOURS	0.00	382.40	529.80	698.15	659.88	538.42	576.98	455.66	267.37	115.99	174.45	122.06	81.82	275.43	664.16	620.58
RSH	0.00	111.65	214.20	14.99	34.99	17.61	131.82	204.97	414.28	627.11	492.45	549.94	134.18	108.58	79.84	90.18
UH	743.00	225.96	0.00	6.86	49.13	187.98	11.20	83.37	39.35	0.89	77.11	0.00	527.00	335.99	0.00	9.24
POH	743.00	194.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	527.00	335.99	0.00	0.00
FOH	0.00	31.13	0.00	6.86	0.00	0.00	0.00	0.00	0.00	0.89	1 04	0.00	0.00	0.00	0.00	9.24
MOH	0.00	0.00	0.00	0.00	49.13	187.98	11.20	83.37	39.35	0.00	76 07	0.00	0.00	0.00	0.00	0.00
PFOH	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	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	0.00	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	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
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
NPC	582.00	582.00	582.00	582.00	582.00	582.00	582.00	582.00	582.00	582.00	582 00	582.00	582.00	582.00	582.00	582.00

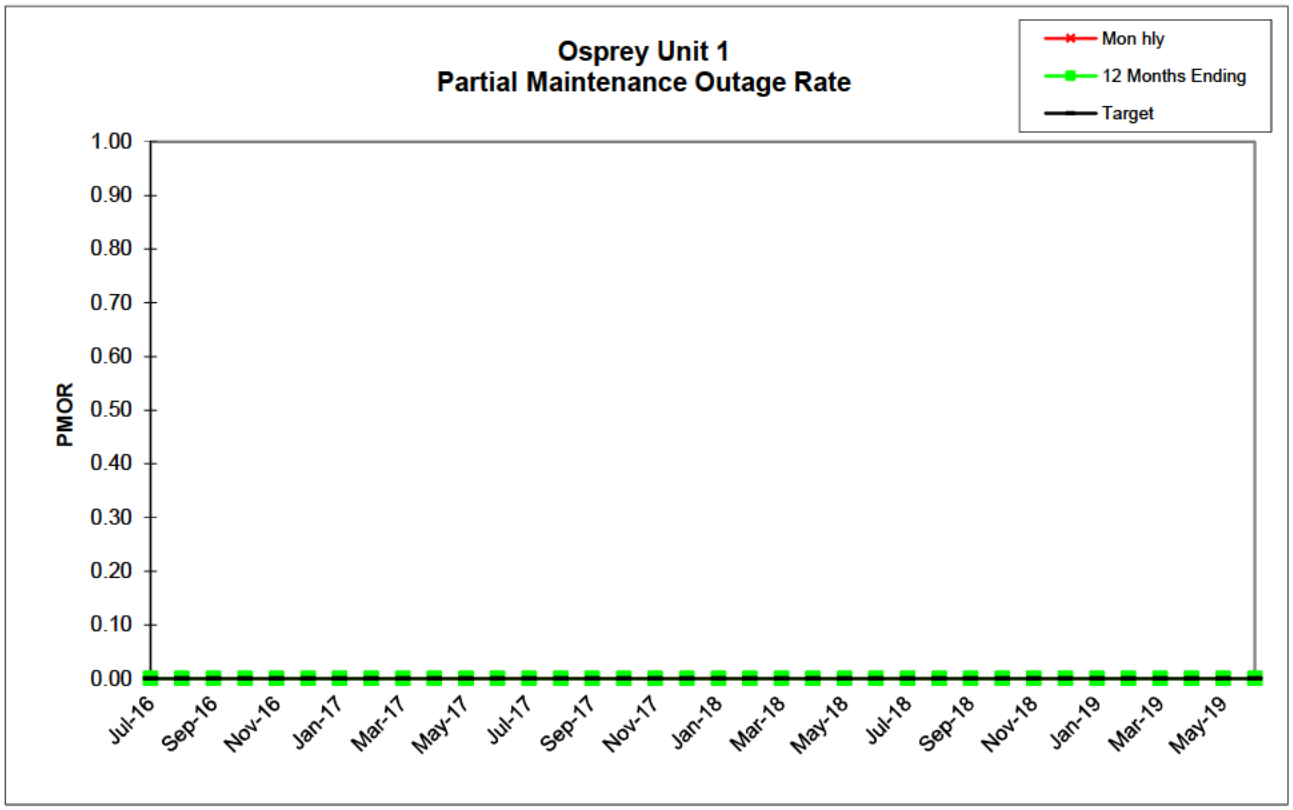
MONTHLY	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
FOR	0.00	7.53	0.00	0.97	0.00	0.00	0.00	0.00	0.00	0.76	0 59	0.00	0.00	0.00	0.00	1.47
MOR	0.00	0.00	0.00	0.00	6.93	25.88	1.90	15.47	12.83	0.00	30 36	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	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	0.00	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	7.53	0.00	0.97	6.93	25.88	1.90	15.47	12.83	0.76	30.65	0.00	0.00	0.00	0.00	1.47
EUOF	0.00	4.32	0.00	0.95	6.60	25.27	1.56	11.21	5.46	0.12	10 36	0.00	0.00	0.00	0.00	1.28
POF	100.00	27.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	70.93	46.67	0.00	0.00
EAF	0.00	68.62	100.00	99.05	93.40	74.73	98.44	88.79	94.54	99.88	89.64	100.00	29.07	53.33	100.00	98.72

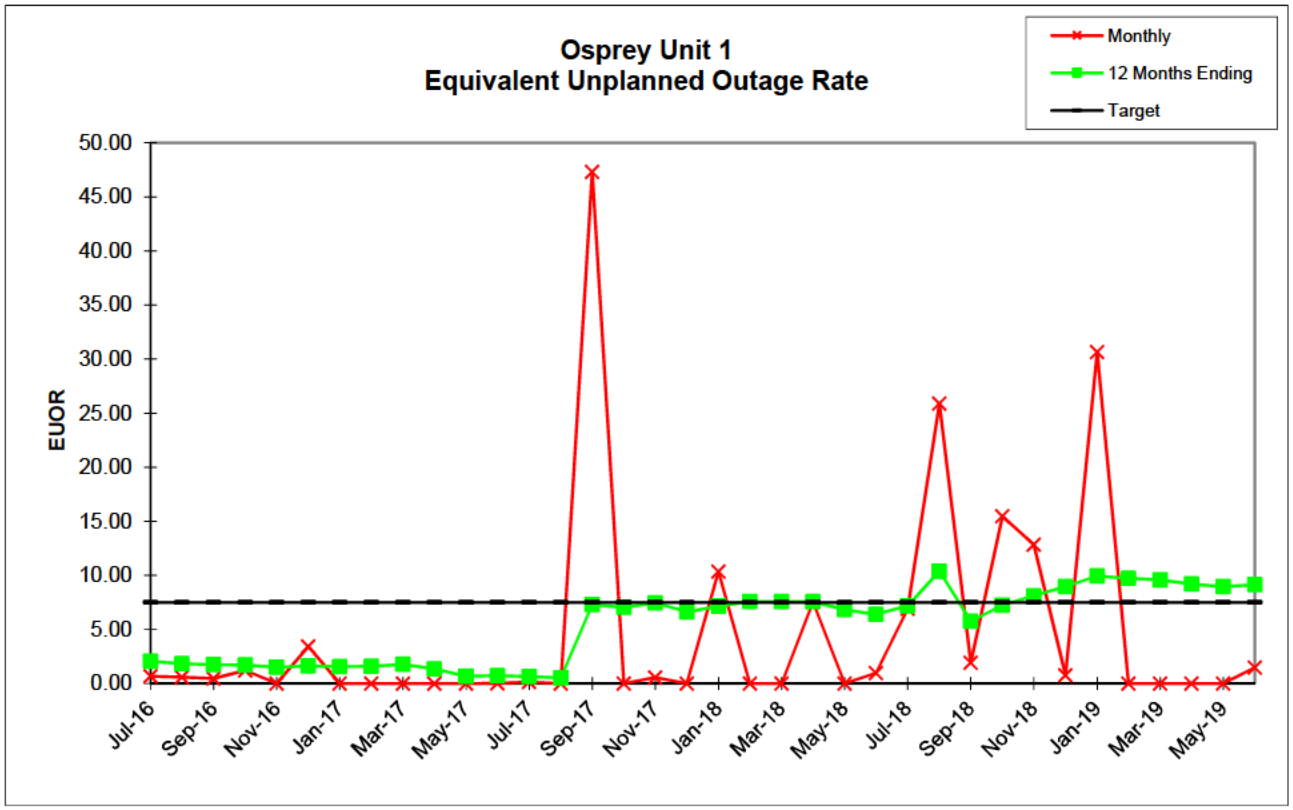
12 MONTHS	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
FOR	1.61	2.14	1.92	1.87	1.87	1.94	1.61	1.65	1.67	1.87	0 90	0.88	0.86	0.20	0.19	0.24
MOR	6.15	5.66	5.10	4.67	5.52	8.77	4.28	5.76	6.66	7.36	9 21	9.00	8.85	9.04	8.81	8.94
PFOR	0.00	0.00	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	0.00	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	7.57	7.57	6.83	6.38	7.18	10.38	5.76	7.23	8.11	8.97	9 95	9.72	9.57	9.21	8.96	9.15
EUOF	3.87	4.23	4.23	4.31	4.86	7.00	3.87	4.82	5.24	5.25	5 56	5.56	5.56	5.20	5.20	5.23
POF	32.14	26.14	17.65	12.08	12.08	12.08	12.08	12.08	12.08	12.08	12 08	10.71	8.24	9.85	9.85	9.85
EAF	63.99	69.63	78.12	83.62	83.07	80.92	84.05	83.10	82.68	82.67	82 36	83.73	86.20	84.94	84.94	84.92

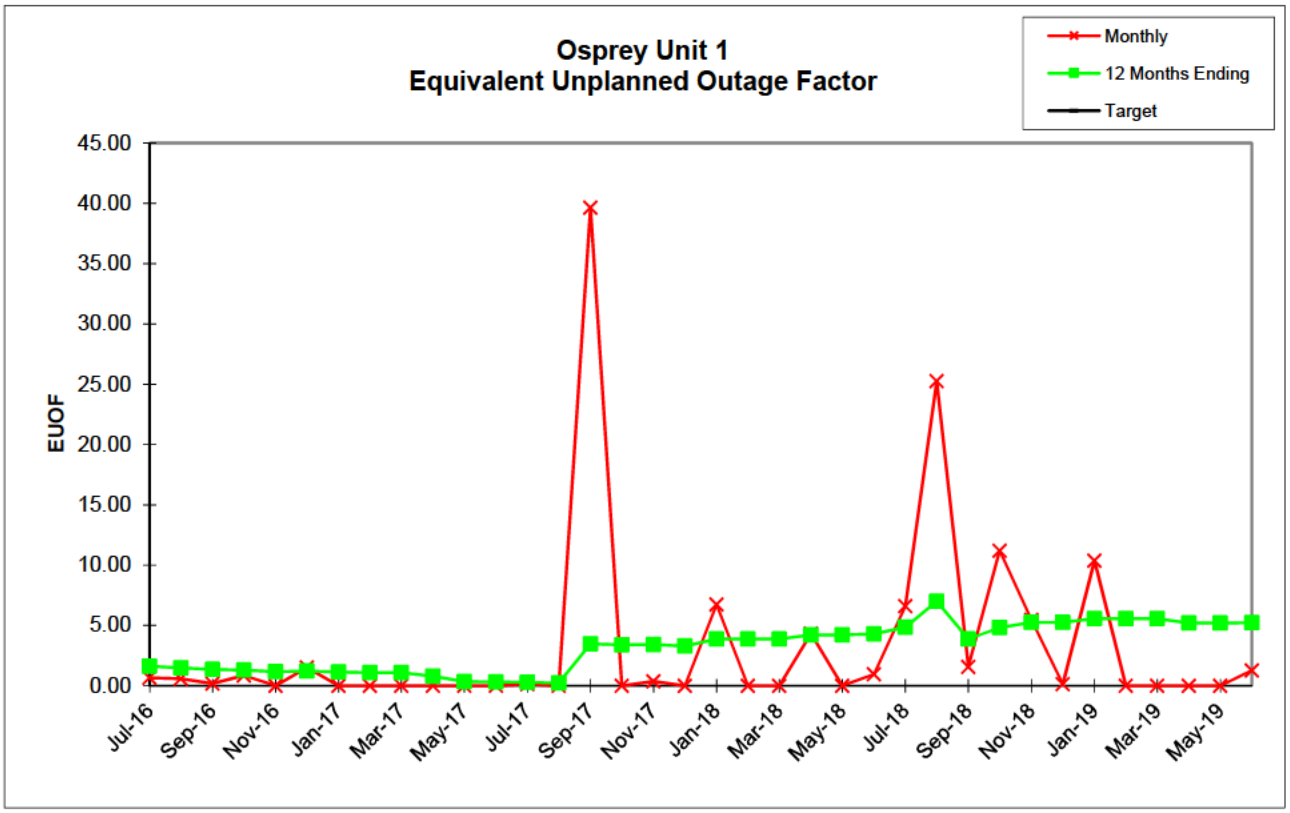

Osprey Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Osprey Unit 1
Maintenance Outage Rate
Monthly
12 Mon hs Ending
Target
MOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Osprey Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Osprey Unit 1
Partial Maintenance Outage Rate
Mon hly
12 Months Ending
Target
PMOR
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Osprey Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19


Osprey Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-16
Sep-16
Nov-16
Jan-17
Mar-17
May-17
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19

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

SCHEDULE: E1-A

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

[1] Page 2, Column 15, Lines 40 & 41

[2] Approved in FPSC Final Order PSC-2018-0610-FOF-EI

Note: Totals may not add due to rounding.

( ) Reflects Underrecovery

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 14
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-1

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

SCHEDULE: E1-B

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	True-up	True Up Line	a-Jan - 2018	a-Feb - 2018	a-Mar - 2018	a-Apr - 2018	a-May - 2018	a-Jun - 2018	a-Jul - 2018	a-Aug - 2018	a-Sep - 2018	a-Oct - 2018	a-Nov - 2018	a-Dec - 2018	a-2018
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	$243,085,192	$233,591,015	$214,637,822	$232,227,371	$249,785,380	$278,196,301	$296,181,995	$302,312,660	$313,118,581	$307,140,535	$269,491,495	$294,578,787	$3,234,347,133
2		SJRPP Fuel Inventory Expense	$4,996,469												$4,996,469
3		Scherer Coal Cars Depreciation & Return			($2,311)	($52,651)									($54,962)
4		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$649,217	$402,076	($182,761)	$463,585	$234,001	$1,034,482	$1,914,506	($66,155)	$797,743	$286,914	$519,804	$690,876	$6,744,289
5		Fuel Cost of Stratified Sales	($826,924)	($2,635,194)	($1,242,878)	($2,454,710)	($896,866)	($2,451,517)	($3,316,610)	($3,092,829)	($2,998,708)	($3,219,174)	($3,081,166)	($2,370,828)	($28,587,406)
6		Fuel Cost of Power Sold (Per A6)	($11,254,619)	($6,322,850)	($6,543,614)	($2,113,385)	($5,410,548)	($2,909,968)	($3,050,183)	($2,924,894)	($1,970,471)	($2,613,083)	($6,344,058)	($8,473,622)	($59,931,294)
7		Gains from Off-System Sales (Per A6)	($12,786,865)	($2,885,156)	($2,843,784)	($806,000)	($2,408,061)	($1,211,737)	($1,326,065)	($634,240)	($1,230,189)	($1,107,285)	($1,645,142)	($2,446,754)	($31,331,278)
8		Fuel Cost of Purchased Power (Per A7)	$3,007,258	$1,463,004	$2,541,679	$2,565,137	$1,240,528	$4,359,681	$1,535,914	$3,072,905	$3,179,060	$1,782,418	$3,759,500	$2,418,183	$30,925,266
9		Energy Payments to Qualifying Facilities (Per A8)	$443,260	$350,206	$284,154	$216,279	$316,743	$474,881	$317,094	$386,056	$546,027	$819,311	$711,947	$603,375	$5,469,331
10		Energy Cost of Economy Purchases (Per A9)	$14,131	$12,615	$8,391	$892,096	$116,832	$1,833,085	$491,910	$1,370,715	$2,542,261	$3,179,247	$55,507	$129,606	$10,646,395
11		Total Fuel Costs & Net Power Transactions	227,327,118	223,975,715	206,656,698	230,937,722	242,978,008	279,325,207	292,748,561	300,424,218	313,984,305	306,268,881	263,467,886	285,129,624	3,173,223,943
12															
13	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$42,272	$37,555	$42,032	$44,237	$49,641	$44,511	$42,505	$44,173	$39,617	$45,255	$43,306	$41,345	$516,451
14		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$264,122	$190,332	$227,335	$62,122	$165,868	$71,172	$69,326	$53,599	$53,191	$61,857	$169,175	$223,022	$1,611,119
15		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($224)	($632)	($140)	($14,803)	($1,565)	($27,905)	($7,095)	($18,615)	($37,304)	($39,380)	($976)	($2,575)	($151,215)
16		Total Incremental Optimization Costs	306,170	227,255	269,228	91,555	213,943	87,778	104,736	79,157	55,504	67,732	211,505	261,791	1,976,355
17															
18	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($40,028)	($104,158)	($31,590)	($38,401)	($67,894)	($107,952)	($147,312)	($79,676)	($107,584)	($170,067)	($166,283)	($89,787)	($1,150,732)
19		Inventory Adjustments	$120,176	$130,505	$3,814	$41,771	$1,035,106	($701,824)	($319,763)	$449,050	$276,930	$30,926	$54,104	($64,411)	$1,056,384
20		Non Recoverable Oil/Tank Bottoms						$222,715							$222,715
21		Other O&M Expense		$1,530				$199,751		$349,662	$20,428	($0)			$571,371
22		Adjusted Total Fuel Costs & Net Power Transactions	227,713,437	224,230,846	206,898,150	231,032,646	244,159,164	279,025,675	292,386,222	301,222,410	314,229,583	306,197,473	263,567,213	285,237,217	3,175,900,036
23															
24	**kWh Sales**	Jurisdictional kWh Sales	8,262,961,939	7,655,562,391	7,658,691,776	8,020,344,013	8,908,457,763	9,630,385,468	10,669,863,413	11,037,589,280	10,444,184,942	10,554,149,683	9,185,318,934	8,025,631,481	110,053,141,083
25		Sales for Resale (excluding Stratified Sales)	401,044,771	440,593,709	406,083,666	407,540,643	449,608,712	461,042,727	544,159,311	580,072,443	556,073,813	544,201,229	514,143,681	426,135,345	5,730,700,050
26		Sub-Total Sales	8,664,006,710	8,096,156,100	8,064,775,442	8,427,884,656	9,358,066,475	10,091,428,195	11,214,022,724	11,617,661,723	11,000,258,755	11,098,350,912	9,699,462,615	8,451,766,826	115,783,841,133
27															
28		**Jurisdictional % of Total Sales (Line 24/26)**	95.37114%	94.55799%	94.96472%	95.16438%	95.19550%	95.43134%	95.14751%	95.00698%	94.94490%	95.09656%	94.69926%	94.95803%	95.05052%
29															
30	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$215,083,204	$198,105,794	$194,179,392	$204,602,796	$229,930,394	$250,662,270	$281,327,173	$292,069,109	$276,639,549	$279,679,927	$239,212,570	$206,106,538	$2,867,598,717
31															
32	**Fuel Adjustment Revenues Not Applicable to Period**														
33		Prior Period True-Up (Collected)/Refunded This Period [2]	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$16,792,378
34		GPIF, Net of Revenue Taxes [3]	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($9,649,084)
35		Incentive Mechanism, Net of Revenue Taxes [5]	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($9,526,193)
36		Jurisdictional Fuel Revenues Applicable to Period	214,884,629	197,907,219	193,980,817	204,404,221	229,731,820	250,463,695	281,128,598	291,870,534	276,440,974	279,481,352	239,013,995	205,907,963	2,865,215,818
37		Adjusted Total Fuel Costs & Net Power Transactions	227,713,437	224,230,846	206,898,150	231,032,646	244,159,164	279,025,675	292,386,222	301,222,410	314,229,583	306,197,473	263,567,213	285,237,217	3,175,900,036
38		Jurisdictional Sales % of Total kWh Sales (Line 28)	95.37114%	94.55799%	94.96472%	95.16438%	95.19550%	95.43134%	95.14751%	95.00698%	94.94490%	95.09656%	94.69926%	94.95803%	95.05052%
39		Juris. Total Fuel Costs & Net Power Trans. (Line 37xLine38x1.00133)	217,461,740	212,310,178	196,741,567	220,153,200	232,737,667	266,632,090	278,568,213	286,562,937	298,741,763	291,570,537	249,928,163	271,215,880	3,022,623,937
40		True-Up Provision for the Month-Over/(Under) Recovery (Line 36-Line 39)	($2,577,111)	($14,402,959)	($2,760,750)	($15,748,980)	($3,005,847)	($16,168,395)	$2,560,385	$5,307,597	($22,300,788)	($12,089,185)	($10,914,168)	($65,307,917)	($157,408,119)
41		Interest Provision for the Month	($11,182)	($24,035)	($41,664)	($60,952)	($77,915)	($98,387)	($114,896)	($110,903)	($134,815)	($179,107)	($207,612)	($292,538)	($1,354,005)
42		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	$16,792,378	$12,804,720	($3,021,640)	($7,223,419)	($24,432,716)	($28,915,842)	($46,581,989)	($45,535,864)	($41,738,535)	($65,573,504)	($79,241,160)	($91,762,304)	$16,792,378
43		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)
44		Prior Period True-Up Collected/(Refunded) This Period	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($16,792,378)
45		End of Period Net True-up Amount Over/(Under) Recovery (Line 40 - 44)	($10,827,547)	($26,653,907)	($30,855,686)	($48,064,983)	($52,548,109)	($70,214,256)	($69,168,131)	($65,370,802)	($89,205,771)	($102,873,427)	($115,394,571)	($182,394,391)	($182,394,391)
46															
47															

48 [1] Actuals include various adjustments as noted on the A-Schedules

49 [2] Prior Period 2017 Actual/Estimated True-up

50 [3] Generating Performance Incentive Factor is (($9,656,036/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI

51 [4] Other Fuel Expense consists of nuclear fuel design software maintenance costs

52 [5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($9,533,057/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI

53 [6] 2017 Final True-up

54

55 Note: Totals may not add due to rounding

56

57 ( ) Reflects Underrecovery

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

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

[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 2017 Actual/Estimated True-up

[4] Generating Performance Incentive Factor is (($9,656,036/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI

[5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($9,533,057/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI

[6] 2017 Final True-up

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

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 15
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-2

Docket No. 20190001-EI
2018 CCR Final True Up
Exhibit RBD-2, Page 1 of 19

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

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

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

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

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

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

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

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

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

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

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

For the Month of **Dec-18**

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

QF = Qualifying Facility

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

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

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

For the Month of **Dec-18**

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

2018 Capacity in MW

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

2018 Capacity in Dollars

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

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

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

True ups												
1												
2												
3												
4												
5												

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

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

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

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

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

Line No.	Strata	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	**General**	Investments														
2		a.Expenditures/Additions														
3		b.Clearings to Plant														
4		c.Retirements														
5		d.Other														
6																
7		Plant-In-Service/Depreciation Base	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	N/A
8		Less: Accumulated Depreciation	$59,518	$61,940	$64,361	$66,782	$69,204	$71,625	$74,047	$76,468	$87,250	$98,032	$100,453	$102,875	$105,296	N/A
9		CWIP - Non Interest Bearing														N/A
10																
11		Net Investment (Lines 7 - 8 + 9)	$85,766	$83,344	$80,923	$78,501	$76,080	$73,659	$71,237	$68,816	$58,034	$47,252	$44,831	$42,409	$39,988	N/A
12																
13		Average Net Investment		$84,555	$82,134	$79,712	$77,291	$74,869	$72,448	$70,027	$63,425	$52,643	$46,041	$43,620	$41,199	N/A
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes		$455	$442	$429	$416	$403	$390	$369	$334	$277	$242	$230	$217	$4,205
17		b.Debt Component (Line 13 x debt rate x 1/12)		$95	$92	$89	$86	$84	$81	$78	$70	$58	$51	$48	$46	$878
18																
19		Investment Expenses														
20		a.Depreciation		$2,421	$2,421	$2,421	$2,421	$2,421	$2,421	$2,421	$10,782	$10,782	$2,421	$2,421	$2,421	$45,778
21		b.Amortization														
22		c.Other														
23																
24		Total System Recoverable Costs (Lines 15 & 19)		$2,971	$2,956	$2,940	$2,924	$2,908	$2,893	$2,868	$11,186	$11,117	$2,715	$2,699	$2,684	$50,861
25																
26																
27																

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

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

Line No.	Strata	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	**Intermediate**	Investments														
2		a.Expenditures/Additions														
3		b.Clearings to Plant														
4		c.Retirements														
5		d.Other														
6																
7		Plant-In-Service/Depreciation Base	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	N/A
8		Less: Accumulated Depreciation	$399,817	$415,062	$430,307	$445,551	$460,796	$475,999	$491,159	$506,319	$521,479	$536,639	$551,799	$566,958	$582,118	N/A
9		CWIP - Non Interest Bearing														N/A
10																
11		Net Investment (Lines 7 - 8 + 9)	$4,941,168	$4,925,923	$4,910,678	$4,895,433	$4,880,188	$4,864,985	$4,849,825	$4,834,665	$4,819,506	$4,804,346	$4,789,186	$4,774,026	$4,758,866	N/A
12																
13		Average Net Investment		$4,933,545	$4,918,300	$4,903,055	$4,887,810	$4,872,587	$4,857,405	$4,842,245	$4,827,086	$4,811,926	$4,796,766	$4,781,606	$4,766,446	N/A
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes		$26,572	$26,490	$26,408	$26,326	$26,244	$26,162	$25,489	$25,409	$25,329	$25,249	$25,169	$25,090	$309,936
17		b.Debt Component (Line 13 x debt rate x 1/12)		$5,515	$5,498	$5,481	$5,464	$5,447	$5,430	$5,366	$5,349	$5,332	$5,315	$5,298	$5,282	$64,775
18																
19		Investment Expenses														
20		a.Depreciation		$15,245	$15,245	$15,245	$15,245	$15,202	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$182,302
21		b.Amortization														
22		c.Other														
23																
24		Total System Recoverable Costs (Lines 15 & 19)		$47,332	$47,232	$47,133	$47,034	$46,893	$46,751	$46,014	$45,918	$45,821	$45,725	$45,628	$45,531	$557,012
25																
26																
27																

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

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

Line No.	Strata	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	**Peaking**	Investments														
2		a.Expenditures/Additions														
3		b.Clearings to Plant														
4		c.Retirements														
5		d.Other														
6																
7		Plant-In-Service/Depreciation Base	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	N/A
8		Less: Accumulated Depreciation	$75,740	$78,670	$81,599	$84,528	$87,457	$90,386	$93,316	$96,245	$99,174	$102,103	$105,032	$107,961	$110,891	N/A
9		CWIP - Non Interest Bearing														N/A
10																
11		Net Investment (Lines 7 - 8 + 9)	$597,043	$594,113	$591,184	$588,255	$585,326	$582,397	$579,467	$576,538	$573,609	$570,680	$567,751	$564,821	$561,892	N/A
12																
13		Average Net Investment		$595,578	$592,649	$589,720	$586,790	$583,861	$580,932	$578,003	$575,074	$572,144	$569,215	$566,286	$563,357	N/A
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes		$3,208	$3,192	$3,176	$3,160	$3,145	$3,129	$3,042	$3,027	$3,012	$2,996	$2,981	$2,965	$37,034
17		b.Debt Component (Line 13 x debt rate x 1/12)		$666	$662	$659	$656	$653	$649	$640	$637	$634	$631	$628	$624	$7,740
18																
19		Investment Expenses														
20		a.Depreciation		$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$35,150
21		b.Amortization														
22		c.Other														
23																
24		Total System Recoverable Costs (Lines 15 & 19)		$6,803	$6,784	$6,765	$6,746	$6,726	$6,707	$6,612	$6,594	$6,575	$6,556	$6,538	$6,519	$79,923
25																
26																
27																

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

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

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

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

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

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

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

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

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

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

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

20 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report
21 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.
22 [b] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297%
23 based on the May 2018 Earnings Surveillance Report.
24 [c] Recovery of the Indiantown Transaction is based on the settlement agreement approved by the FPSC in Docket No. 160154-EI, Order No. PSC-16-0506-FOF-EI.
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27 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 2018 THROUGH DECEMBER 2018

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

26 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report
27 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.
28 [b] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earnings Surveillance Report.
29 [c] Recovery of the SJRPP Transaction over a 46 month period is based on the settlement agreement approved by the FPSC in Docket No. 20170123-EI Order No. PSC-2017-0415-AS-EI.
30 [d] The total amount of SJRPP Deferred Interest and Article 8 PPA Dismantlement Accrual to refund is $12.4M and $39.9M, respectively. The unamortized balances for these regulatory liabilities are reflected in rate base.
31
32 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

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

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

DEBT COMPONENTS:

LONG TERM DEBT	1.2592%
SHORT TERM DEBT	0.0501%
CUSTOMER DEPOSITS	0.0285%
TAX CREDITS -WEIGHTED	0.0035%
TOTAL DEBT	**1.3413%**

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8119%
TAX CREDITS -WEIGHTED	0.0132%
TOTAL EQUITY	**4.8251%**
TOTAL	6.1663%
PRE-TAX EQUITY	7.8552%
PRE-TAX TOTAL	9.1965%

Note:

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

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2018 EARNINGS SURVEILLANCE REPORT

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

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

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

DEBT COMPONENTS:

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

EQUITY COMPONENTS:

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

Note:

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

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2019 THROUGH DECEMBER 2019

SCHEDULE: E1-B

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	True Up Section	True Up Line	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	a-Jan - 2019	$210,407,736	$239,033,820	$240,339,290	$265,852,130	$260,852,387	$233,413,813	$235,472,852	$213,914,527	$211,280,134	$187,835,304	$196,648,933	$2,742,695,965
2		Fuel Cost of Stratified Sales	($2,502,014)	($1,682,735)	($1,748,714)	($2,688,498)	($2,785,905)	($3,537,668)	($2,902,500)	($2,743,512)	($2,580,250)	($2,317,483)	($1,740,338)	($973,263)	($28,202,880)
3		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$431,592	$200,773	$517,637	$288,456	$312,932	$111,960	$157,046	$157,683	$157,683	$157,046	$157,683	$157,046	$2,807,537
4		Fuel Cost of Power Sold (Per A6)	($9,633,494)	($7,019,582)	($6,246,138)	($4,379,818)	($2,828,622)	($2,657,301)	($2,680,311)	($2,996,176)	($2,698,192)	($2,002,940)	($3,708,535)	($5,285,334)	($52,136,444)
5		Gains from Off-System Sales (Per A6)	($4,922,077)	($2,729,301)	($2,317,588)	($1,920,408)	($951,695)	($938,229)	($1,160,156)	($1,072,352)	($1,238,698)	($885,028)	($1,440,042)	($2,226,670)	($21,802,243)
6		Fuel Cost of Purchased Power (Per A7)	$2,985,541	$1,982,779	$2,690,113	$2,385,026	$2,396,171	$3,608,732	$2,645,660	$2,724,071	$2,347,810	$2,540,888	$2,219,472	$2,367,349	$30,893,610
7		Energy Payments to Qualifying Facilities (Per A8)	$590,447	$379,280	$398,998	$336,858	$462,632	$639,663	$354,498	$401,952	$435,193	$478,743	$391,257	$587,840	$5,457,362
8		Energy Cost of Economy Purchases (Per A9)	$30,784	$32,530	$559,838	$610,393	$5,635,526	$10,448,887	$1,442,895	$2,823,480	$1,462,800	$881,640	$127,500	$52,080	$24,108,353
9		Total Fuel Costs & Net Power Transactions	$234,625,816	$201,571,479	$232,887,967	$234,971,299	$268,093,168	$268,528,431	$231,270,945	$234,767,999	$211,800,872	$210,133,001	$183,842,300	$191,327,981	$2,703,821,260
10															
11	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$45,273	$40,940	$38,239	$40,305	$56,630	$42,240	$44,148	$44,148	$43,056	$44,148	$43,056	$44,148	$526,330
12		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$289,804	$224,878	$203,849	$141,000	$87,966	$84,664	$74,354	$72,540	$75,758	$62,465	$126,750	$185,884	$1,629,911
13		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($1,067)	($832)	($8,941)	($9,068)	($74,779)	($145,473)	($32,341)	($55,614)	($41,340)	($31,837)	($4,875)	($2,116)	($408,282)
14		Total Incremental Optimization Costs	$334,010	$264,985	$233,147	$172,237	$69,817	($18,568)	$86,161	$61,074	$77,474	$74,776	$164,931	$227,916	$1,747,960
15															
16															
17	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($177,786)	($133,355)	($3,715)	($58,853)	($171,860)	($25,305)	-	-	-	-	-	-	($570,875)
18		Inventory Adjustments	($53,094)	$18,214	($179,394)	$360,284	$705,754	($1,110,949)	-	-	-	-	-	-	($259,185)
19		Non Recoverable Oil/Tank Bottoms	-	-	$232,871	($549,227)	-	($1,051,361)	-	-	-	-	-	-	($1,367,716)
20		Other O&M Expense [2]	-	-	-	$1,554	$205,738	-	$337,189	$21,041	-	-	-	-	$565,522
21		Adjusted Total Fuel Costs & Net Power Transactions	$234,728,946	$201,721,323	$233,170,876	$234,897,293	$268,902,617	$266,322,249	$231,694,295	$234,850,113	$211,878,346	$210,207,777	$184,007,231	$191,555,897	$2,703,936,965
22															
23	**kWh Sales**	Jurisdictional kWh Sales	8,090,450,684	7,361,664,859	7,987,648,669	8,430,422,795	9,195,507,367	10,476,195,510	10,839,231,698	10,866,566,527	10,587,934,385	9,898,111,995	8,490,529,849	8,113,588,354	110,337,852,692
24		Sales for Resale (excluding Stratified Sales)	398,798,783	418,248,548	387,890,789	426,072,948	452,801,248	540,722,792	467,014,153	500,590,058	475,396,860	423,631,488	406,885,888	339,694,015	5,237,747,569
25		Total Sales	8,489,249,467	7,779,913,407	8,375,539,458	8,856,495,743	9,648,308,615	11,016,918,302	11,306,245,851	11,367,156,585	11,063,331,245	10,321,743,483	8,897,415,737	8,453,282,369	115,575,600,261
26															
27		Jurisdictional % of Total Sales (Line 23/25)	95.30231%	94.62399%	95.36877%	95.18915%	95.30694%	95.09189%	95.86941%	95.59617%	95.70295%	95.89574%	95.42692%	95.98151%	95.46812%
28															
29	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$216,746,520	$194,169,194	$211,711,391	$211,291,072	$233,391,232	$269,773,583	$276,309,714	$277,006,524	$269,903,735	$252,319,036	$216,437,469	$206,828,615	$2,835,888,086
30		Fuel Adjustment Revenues Not Applicable to Period													
31		Prior Period True-Up (Collected)/Refunded This Period [3]	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($111,740,516)
32		GPIF, Net of Revenue Taxes [4]	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($5,853,723)
33		Incentive Mechanism, Net of Revenue Taxes [5]	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($2,202,961)
34		**Jurisdictional Fuel Revenues Applicable to Period**	$206,763,420	$184,186,094	$201,728,291	$201,307,972	$223,408,132	$259,790,483	$266,326,614	$267,023,424	$259,920,635	$242,335,936	$206,454,369	$196,845,515	$2,716,090,886
35		Adjusted Total Fuel Costs & Net Power Transactions	234,728,946	201,721,323	233,170,876	234,897,293	268,902,617	266,322,249	231,694,295	234,850,113	211,878,346	210,207,777	184,007,231	191,555,897	2,703,936,965
36		Jurisdictional Sales % of Total kWh Sales (Line 27)	95.30231%	94.62399%	95.36877%	95.18915%	95.30694%	95.09189%	95.86941%	95.59617%	95.70295%	95.89574%	95.42692%	95.98151%	95.46812%
37		Juris. Total Fuel Costs & Net Power Trans. (Line 35xLine36x1.00139)	224,013,054	191,142,083	222,681,294	223,907,536	256,639,089	253,602,879	222,432,706	224,619,779	203,055,683	201,860,500	175,836,507	184,113,806	2,584,104,916
38		True-Up Provision for the Month-Over/(Under) Recovery (Line 34- Line 37)	($17,249,634)	($6,955,989)	($20,953,003)	($22,599,564)	($33,230,957)	$6,187,604	$43,893,908	$42,203,644	$56,864,952	$40,475,436	$30,617,862	$12,731,709	$131,985,970
39		Interest Provision for the Month	($375,832)	($381,429)	($396,404)	($424,337)	($454,773)	($453,549)	($381,264)	($280,772)	($167,548)	($55,776)	$30,841	$90,807	($3,250,033)
40		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	($111,740,516)	($120,054,272)	($118,079,980)	($130,117,677)	($143,829,868)	($168,203,888)	($153,158,123)	($100,333,769)	($49,099,187)	$16,909,927	$66,641,297	$106,601,711	($111,740,516)
41		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)
42		Prior Period True-Up Collected/(Refunded) This Period	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$111,740,516
43		**End of Period Net True-up Amount Over/(Under) Recovery (Line 38 through 42)**	($190,707,677)	($188,733,385)	($200,771,082)	($214,483,273)	($238,857,293)	($223,811,528)	($170,987,174)	($119,752,592)	($53,743,478)	($4,012,108)	$35,948,306	$58,082,532	$58,082,532
44															
45															

[1] Actuals include various adjustments as noted on the A-Schedules

[2] Other Fuel Expense consists of nuclear fuel design software maintenance costs

[3] 2018 End of Period Net True-up Over/(Under) Recovery

[4] Generating Performance Incentive Factor is (($5,857,941/12) x 99.9280%) - See Order No. PSC-2018-0610-FOF-EI

[5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($2,204,548/12) x 99.9280%) - See Order No. PSC-2018-0610-FOF-EI

[6] 2018 Final True-up

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 16
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-3

Docket No. 20190001-EI
2019 FCR Actual Estimated
Exhibit RBD-3, Page 1 of 27

FUEL COST RECOVERY CLAUSE
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	True Up Section	True Up Line	2019 Actual/Estimated	2019 Projection	2019 Difference	2019 % Difference
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	$2,742,695,965	$2,861,862,723	($119,166,758)	(4.2%)
2		Fuel Cost of Stratified Sales	($28,202,880)	($21,588,417)	($6,614,463)	30.6%
3		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$2,807,537	$2,770,763	$36,774	1.3%
4		Fuel Cost of Power Sold (Per A6)	($52,136,444)	($56,929,285)	$4,792,841	(8.4%)
5		Gains from Off-System Sales (Per A6)	($21,802,243)	($19,812,410)	($1,989,833)	10.0%
6		Fuel Cost of Purchased Power (Per A7)	$30,893,610	$32,794,015	($1,900,404)	(5.8%)
7		Energy Payments to Qualifying Facilities (Per A8)	$5,457,362	$5,961,696	($504,335)	(8.5%)
8		Energy Cost of Economy Purchases (Per A9)	$24,108,353	$14,167,400	$9,940,953	70.2%
9		Total Fuel Costs & Net Power Transactions	2,703,821,260	2,819,226,485	($115,405,225)	(4.1%)
10						
11	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$526,330	$509,164	$17,166	3.4%
12		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$1,629,911	$1,424,563	$205,349	14.4%
13		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($408,282)	($357,809)	($50,473)	14.1%
14		Total Incremental Optimization Costs	$1,747,960	$1,575,918	$172,042	10.9%
15						
16						
17	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($570,875)	$0	($570,875)	N/A
18		Inventory Adjustments	($259,185)	$0	($259,185)	N/A
19		Non Recoverable Oil/Tank Bottoms	($1,367,716)	$0	($1,367,716)	N/A
20		Other O&M Expense [2]	$565,522	$553,961	$11,561	2.1%
21		Adjusted Total Fuel Costs & Net Power Transactions	$2,703,936,965	$2,821,356,363	($117,419,399)	(4.2%)
22						
23	**kWh Sales**	Jurisdictional kWh Sales	110,337,852,692	108,208,558,910	2,129,293,782	2.0%
24		Sales for Resale (excluding Stratified Sales)	5,237,747,569	4,734,431,804	503,315,765	10.6%
25		Total Sales	115,575,600,261	112,942,990,715	2,632,609,546	2.3%
26						
27		Jurisdictional % of Total Sales (Line 23/25)	N/A	N/A	N/A	N/A
28						
29	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$2,835,888,086	$2,826,870,487	$9,017,599	0.3%
30		Fuel Adjustment Revenues Not Applicable to Period				
31		Prior Period True-Up (Collected)/Refunded This Period [3]	($111,740,516)	($111,740,516)	$0	0.0%
32		GPIF, Net of Revenue Taxes [4]	($5,853,723)	($5,853,723)	$0	0.0%
33		Incentive Mechanism, Net of Revenue Taxes [5]	($2,202,961)	($2,202,961)	$0	0.0%
34		**Jurisdictional Fuel Revenues Applicable to Period**	$2,716,090,886	$2,707,073,287	$9,017,599	0.3%
35		Adjusted Total Fuel Costs & Net Power Transactions	$2,703,936,965	$2,821,356,363	($117,419,399)	(4.2%)
36		Jurisdictional Sales % of Total kWh Sales (Line 27)	N/A	N/A	N/A	N/A
37		Juris. Total Fuel Costs & Net Power Trans. (Line 35xLine36x1.00139)	$2,584,104,916	$2,707,073,287	($122,968,371)	(4.5%)
38		True-Up Provision for the Month-Over/(Under) Recovery (Line 34- Line 37)	$131,985,970	$0	$131,985,970	N/A
39		Interest Provision for the Month	($3,250,033)	$0	($3,250,033)	N/A
40		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	($111,740,516)	($111,740,516)	$0	0.0%
41		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($70,653,405)	$0	($70,653,405)	N/A
42		Prior Period True-Up Collected/(Refunded) This Period	$111,740,516	$111,740,516	$0	0.0%
43		**End of Period Net True-up Amount Over/(Under) Recovery (Line 38 through 42)**	$58,082,532	$0	$58,082,532	N/A
44						
45						

46 [1] Actuals include various adjustments as noted on the A-Schedules

47 [2] Other Fuel Expense consists of nuclear fuel design software maintenance costs

48 [3] 2018 End of Period Net True-up Over/(Under) Recovery

49 [4] Generating Performance Incentive Factor is ($5,857,941 x 99.9280%) - See Order No. PSC-2018-0610-FOF-EI

50 [5] Jurisdictionalized Incentive Mechanism - FPL Portion is ($2,204,548 x 99.9280%) - See Order No. PSC-2018-0610-FOF-EI

51 [6] 2018 Final True-up

52

53 Note: Totals may not add due to rounding.

54

55 ( ) Reflects Underrecovery

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

SCHEDULE E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	Fuel Data Category	Fuel Type for Reporting	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	As Burned Fuel Cost ($)	Heavy Oil	312	175,154	1,514,755	1,968,602	3,299,209	3,540,260	500,463	1,854,658	0	0	0	0	12,853,413
2		Light Oil	1,772,457	5,004,479	1,719,580	1,001,213	899,256	1,283,074	0	312,139	0	0	0	0	11,992,197
3		Coal	5,532,181	5,124,930	6,380,502	5,444,667	7,705,798	6,765,450	5,759,497	5,633,691	5,199,752	5,401,930	5,070,481	5,170,150	69,189,030
4		Gas	225,326,381	186,675,032	216,693,857	219,361,512	243,296,912	237,476,593	213,293,114	213,811,626	195,301,157	194,142,858	170,984,755	177,251,491	2,493,615,287
5		Nuclear	15,013,707	13,486,733	12,666,533	12,563,297	10,645,688	11,792,278	13,860,739	13,860,739	13,413,619	11,735,345	11,780,068	14,227,293	155,046,037
6		Total As Burned Fuel Cost ($)	247,645,037	210,466,328	238,975,227	240,339,291	265,846,864	260,857,654	233,413,813	235,472,852	213,914,527	211,280,134	187,835,304	196,648,933	2,742,695,965
7															
8	Net Generation (MWH)	Heavy Oil	(2,505)	1,364	11,932	15,428	26,474	27,792	3,840	14,514	0	0	0	0	98,840
9		Light Oil	69,250	33,402	13,433	6,830	7,266	9,113	0	1,444	0	0	0	0	140,739
10		Coal	181,661	169,249	217,807	186,421	268,083	221,108	201,171	196,615	180,826	188,812	176,857	179,521	2,368,131
11		Gas	5,968,591	5,849,339	6,701,058	7,405,223	8,939,365	9,086,126	9,078,410	9,149,996	8,357,583	7,921,157	6,423,493	6,140,194	91,020,535
12		Nuclear	2,672,311	2,407,535	2,223,287	2,185,325	1,855,413	2,044,834	2,523,667	2,523,667	2,442,258	2,110,443	2,130,359	2,589,680	27,708,778
13		Solar [c]	159,296	163,420	218,058	231,616	244,343	204,940	248,328	240,035	222,645	227,320	201,508	184,776	2,546,285
14		Total Net Generation (MWH)	9,048,604	8,624,310	9,385,575	10,030,843	11,340,944	11,593,913	12,055,416	12,126,271	11,203,312	10,447,731	8,932,217	9,094,171	123,883,308
15															
16	Fuel Burned (Units) [a]	Heavy Oil	4	2,400	20,753	26,971	45,201	48,504	6,857	25,223	0	0	0	0	175,912
17		Light Oil	18,482	51,724	17,766	9,153	9,037	12,366	0	3,495	0	0	0	0	122,023
18		Coal [b]	123,052	119,449	148,334	121,996	180,886	153,350	133,724	131,080	121,362	126,530	118,856	121,005	1,599,623
19		Gas	42,166,834	40,932,526	47,950,595	52,067,737	63,495,421	63,809,976	62,307,670	63,037,578	56,817,986	54,197,831	43,359,891	41,226,799	631,370,843
20		Nuclear	28,673,550	25,914,094	24,002,476	23,834,172	20,673,517	22,748,812	26,918,706	26,918,706	26,050,362	22,540,065	22,758,319	27,623,065	298,655,844
21															
22	Fuel Burned (MMBTU)	Heavy Oil	27	15,189	131,345	170,698	286,076	306,984	43,882	161,424	0	0	0	0	1,115,625
23		Light Oil	106,710	298,729	102,657	53,774	52,186	72,081	0	20,373	0	0	0	0	706,510
24		Coal	2,225,086	2,008,824	2,476,511	2,106,119	2,998,512	2,592,368	2,273,307	2,228,356	2,063,155	2,151,018	2,020,550	2,057,085	27,200,891
25		Gas	42,984,306	41,683,522	48,860,892	53,151,368	64,871,543	65,398,885	62,307,670	63,037,578	56,817,986	54,197,831	43,359,891	41,226,799	637,898,271
26		Nuclear	28,673,550	25,914,094	24,002,476	23,834,172	20,673,517	22,748,812	26,918,706	26,918,706	26,050,362	22,540,065	22,758,319	27,623,065	298,655,844
27		Total Fuel Burned (MMBTU)	73,989,680	69,920,357	75,573,881	79,316,132	88,881,833	91,119,130	91,543,565	92,366,437	84,931,503	78,888,914	68,138,760	70,906,949	965,577,141
28															
29	Cost of Fuel ($/Unit)	Heavy Oil	70.8773	72.9855	72.9900	72.9900	72.9901	72.9886	72.9904	73.5319	0.0000	0.0000	0.0000	0.0000	73.0672
30		Light Oil	95.9018	96.7535	96.7905	109.3863	99.5082	103.7582	0.0000	89.3227	0.0000	0.0000	0.0000	0.0000	98.2786
31		Coal	44.9581	42.9049	43.0143	44.6301	42.6003	44.1178	43.0701	42.9791	42.8450	42.6927	42.6608	42.7267	43.2533
32		Gas	5.3437	4.5606	4.5191	4.2130	3.8317	3.7216	3.4232	3.3918	3.4373	3.5821	3.9434	4.2994	3.9495
33		Nuclear	0.5236	0.5204	0.5277	0.5271	0.5149	0.5184	0.5149	0.5149	0.5149	0.5206	0.5176	0.5151	0.5191
34															
35	Generator Mix (%)	Heavy Oil	-0.03%	0.02%	0.13%	0.15%	0.23%	0.24%	0.03%	0.12%	0.00%	0.00%	0.00%	0.00%	0.08%
36		Light Oil	0.77%	0.39%	0.14%	0.07%	0.06%	0.08%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.11%
37		Coal	2.01%	1.96%	2.32%	1.86%	2.36%	1.91%	1.67%	1.62%	1.61%	1.81%	1.98%	1.97%	1.91%
38		Gas	65.96%	67.82%	71.40%	73.82%	78.82%	78.37%	75.31%	75.46%	74.60%	75.82%	71.91%	67.52%	73.47%
39		Nuclear	29.53%	27.92%	23.69%	21.79%	16.36%	17.64%	20.93%	20.81%	21.80%	20.20%	23.85%	28.48%	22.37%
40		Solar	1.76%	1.89%	2.32%	2.31%	2.15%	1.77%	2.06%	1.98%	1.99%	2.18%	2.26%	2.03%	2.06%
41		Total Generation Mix %	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%

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

SCHEDULE E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	Fuel Data Category	Fuel Type for Reporting	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
42															
43	Fuel Cost Per MMBTU ($/MMBTU)	Heavy Oil	11.3997	11.5319	11.5326	11.5326	11.5326	11.5324	11.4048	11.4894	0.0000	0.0000	0.0000	0.0000	11.5213
44		Light Oil	16.6100	16.7526	16.7508	18.6188	17.2319	17.8004	0.0000	15.3212	0.0000	0.0000	0.0000	0.0000	16.9739
45		Coal	2.4863	2.5512	2.5764	2.5852	2.5699	2.6098	2.5335	2.5282	2.5203	2.5113	2.5095	2.5133	2.5436
46		Gas	5.2421	4.4784	4.4349	4.1271	3.7504	3.6312	3.4232	3.3918	3.4373	3.5821	3.9434	4.2994	3.9091
47		Nuclear	0.5236	0.5204	0.5277	0.5271	0.5149	0.5184	0.5149	0.5149	0.5149	0.5206	0.5176	0.5151	0.5191
48															
49	BTU Burned Per KWH (BTU/KWH)	Heavy Oil	(11)	11,132	11,008	11,064	10,806	11,046	11,427	11,122	0	0	0	0	11,287
50		Light Oil	1,541	8,943	7,642	7,873	7,182	7,910	0	14,108	0	0	0	0	5,020
51		Coal	12,249	11,869	11,370	11,298	11,185	11,724	11,300	11,334	11,410	11,392	11,425	11,459	11,486
52		Gas	7,202	7,126	7,292	7,178	7,257	7,198	6,863	6,889	6,798	6,842	6,750	6,714	7,008
53		Nuclear	10,730	10,764	10,796	10,906	11,142	11,125	10,667	10,667	10,667	10,680	10,683	10,667	10,778
54															
55	Cost if Generated (cents/KWH)	Heavy Oil	(0.0124)	12.8368	12.6947	12.7601	12.4621	12.7383	13.0318	12.7782	0.0000	0.0000	0.0000	0.0000	13.0042
56		Light Oil	2.5595	14.9825	12.8013	14.6585	12.3755	14.0793	0.0000	21.6156	0.0000	0.0000	0.0000	0.0000	8.5209
57		Coal	3.0453	3.0280	2.9294	2.9206	2.8744	3.0598	2.8630	2.8653	2.8756	2.8610	2.8670	2.8800	2.9217
58		Gas	3.7752	3.1914	3.2337	2.9623	2.7216	2.6136	2.3495	2.3367	2.3368	2.4509	2.6619	2.8867	2.7396
59		Nuclear	0.5618	0.5602	0.5697	0.5749	0.5738	0.5767	0.5492	0.5492	0.5492	0.5561	0.5530	0.5494	0.5596
60		Total Generated Fuel Cost per KWH (cents/KWH)	2.7368	2.4404	2.5462	2.3960	2.3441	2.2500	1.9362	1.9418	1.9094	2.0223	2.1029	2.1624	2.2139
61															

62 [a] Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER

63 [b] Scherer coal is not reported in Tons, excludes Scherer coal

64 [c] Actuals do not include Martin 8 solar

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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 - 2019**												
2	*Babcock PV Solar*												
3	Solar		14,458					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,458	26.1%	N/A	41.7%	N/A			N/A	N/A	N/A	
5	*Barefoot PV Solar*												
6	Solar		15,868					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,868	28.6%	N/A	52.9%	N/A			N/A	N/A	N/A	
8	*Blue Cypress PV Solar*												
9	Solar		15,415					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,415	27.8%	N/A	51.3%	N/A			N/A	N/A	N/A	
11	*CCEC 3*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		696,633				6,558	4,568,366	1,000,000	4,568,366	15,751,188	2.26	3.45
14	Plant Unit Info	1,281	696,633	73.1%	76.7%	73.1%	6,558			4,568,366	15,751,188	2.26	
15	*Citrus PV Solar*												
16	Solar		14,844					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,844	26.5%	N/A	42.8%	N/A			N/A	N/A	N/A	
18	*Coral Farms PV Solar*												
19	Solar		15,902					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	15,902	28.7%	N/A	53.0%	N/A			N/A	N/A	N/A	
21	*Desoto Solar*												
22	Solar		4,558					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25	4,558	24.5%	N/A	42.0%	N/A			N/A	N/A	N/A	
24	*Fort Myers GT*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	96	0	0.0%	93.3%	0.0%	0			0	0	0.00	
28	*Fort Myers 2*												
29	Gas		843,440				7,056	5,951,116	1,000,000	5,951,116	20,487,656	2.43	3.44
30	Plant Unit Info	1,752	843,440	64.7%	94.0%	64.7%	7,056			5,951,116	20,487,656	2.43	
31	*Fort Myers 3A*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	*Fort Myers 3B*												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00
38	Plant Unit Info	190	0	0.0%	93.5%	0.0%	0			0	0	0.00	
39	*Fort Myers 3C*												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		11,257				10,579	119,085	1,000,000	119,085	409,248	3.64	3.44
42	Plant Unit Info	215	11,257	7.0%	93.5%	93.5%	10,579			119,085	409,248	3.64	
43	*Fort Myers 3D*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		10,453				10,603	110,836	1,000,000	110,836	380,773	3.64	3.44
46	Plant Unit Info	215	10,453	6.5%	93.5%	93.4%	10,603			110,836	380,773	3.64	
47	*Hammock PV Solar*												
48	Solar		15,069					N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	74.5	15,069	27.2%	N/A	50.2%	N/A			N/A	N/A	N/A	
50	*Horizon PV Solar*												
51	Solar		15,922					N/A	N/A	N/A	N/A	N/A	N/A
52	Plant Unit Info	74.5	15,922	28.7%	N/A	53.0%	N/A			N/A	N/A	N/A	
53	*Indiantown FPL*												
54	Coal		0					0	0	0	0	0.00	0.00
55	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Indian River PV Solar*												
2	Solar		15,364					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	15,364	27.7%	N/A	51.2%	N/A			N/A	N/A	N/A	
4	*Interstate PV Solar*												
5	Solar		15,328					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	15,328	27.7%	N/A	51.0%	N/A			N/A	N/A	N/A	
7	*Lauderdale GT*												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	57	0	0.0%	93.3%	0.0%	0			0	0	0.00	
11	*Lauderdale 6A*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		18,391				10,518	193,440	1,000,000	193,440	665,561	3.62	3.44
14	Plant Unit Info	215	18,391	11.5%	94.0%	94.0%	10,518			193,440	665,561	3.62	
15	*Lauderdale 6B*												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		18,593				10,531	195,810	1,000,000	195,810	674,255	3.63	3.44
18	Plant Unit Info	215	18,593	11.6%	94.0%	94.0%	10,531			195,810	674,255	3.63	
19	*Lauderdale 6C*												
20	Gas		18,997				10,525	199,949	1,000,000	199,949	687,596	3.62	3.44
21	Plant Unit Info	215	18,997	11.9%	94.0%	94.0%	10,525			199,949	687,596	3.62	
22	*Lauderdale 6D*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		0					0	0	0	0	0.00	0.00
25	Plant Unit Info	215	0	0.0%	94.0%	0.0%	0			0	0	0.00	
26	*Lauderdale 6E*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		0					0	0	0	0	0.00	0.00
29	Plant Unit Info	215	0	0.0%	94.0%	0.0%	0			0	0	0.00	
30	*Loggerhead PV Solar*												
31	Solar		15,230					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	15,230	27.5%	N/A	50.7%	N/A			N/A	N/A	N/A	
33	*Manatee 1*												
34	Heavy Oil		2,021					3,520	6,400,000	22,527	256,915	12.71	72.99
35	Gas		54,905				11,148	612,090	1,000,000	612,090	2,096,607	3.82	3.43
36	Plant Unit Info	790	56,926	9.7%	96.2%	31.0%	11,148			634,617	2,353,522	4.13	
37	*Manatee 2*												
38	Heavy Oil		1,820					3,337	6,400,000	21,355	243,548	13.38	72.99
39	Gas		43,804				11,736	514,087	1,000,000	514,087	1,761,107	4.02	3.43
40	Plant Unit Info	790	45,624	7.8%	96.2%	32.5%	11,736			535,442	2,004,656	4.39	
41	*Manatee 3*												
42	Gas		450,281				7,374	3,320,445	1,000,000	3,320,445	11,271,609	2.50	3.39
43	Plant Unit Info	1,238	450,281	48.9%	94.1%	72.5%	7,374			3,320,445	11,271,609	2.50	
44	*Manatee PV Solar*												
45	Solar		14,567					N/A	N/A	N/A	N/A	N/A	N/A
46	Plant Unit Info	74.5	14,567	26.3%	N/A	42.0%	N/A			N/A	N/A	N/A	
47	*Martin 3*												
48	Gas		77,189				8,879	685,392	1,000,000	685,392	2,352,034	3.05	3.43
49	Plant Unit Info	476	77,189	21.8%	93.9%	78.0%	8,879			685,392	2,352,034	3.05	
50	*Martin 4*												
51	Gas		79,074				8,779	694,199	1,000,000	694,199	2,379,153	3.01	3.43
52	Plant Unit Info	476	79,074	22.3%	94.0%	79.9%	8,779			694,199	2,379,153	3.01	
53	*Martin 8 Solar*												
54	Solar		12,679					N/A	N/A	N/A	N/A	N/A	N/A
55	Plant Unit Info	75	12,679	22.7%	N/A	36.4%	N/A			N/A	N/A	N/A	
56	*Martin 8*												
57	Light Oil		0					0	0	0	0	0.00	0.00
58	Gas		389,420				7,606	2,962,092	1,000,000	2,962,092	10,151,154	2.61	3.43
59	Plant Unit Info	1,231	389,420	42.5%	94.0%	82.4%	7,606			2,962,092	10,151,154	2.61	
60	*Miami-Dade PV Solar*												
61	Solar		14,947					N/A	N/A	N/A	N/A	N/A	N/A
62	Plant Unit Info	74.5	14,947	27.0%	N/A	49.8%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Okechobee 1*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		1,141,776				6,170	7,044,976	1,000,000	7,044,976	24,367,863	2.13	3.46
4	Plant Unit Info	1,652	1,141,776	92.9%	96.7%	92.9%	6,170			7,044,976	24,367,863	2.13	
5	*PEEC*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		879,332				6,323	5,559,825	1,000,000	5,559,825	19,167,604	2.18	3.45
8	Plant Unit Info	1,264	879,332	93.5%	93.9%	93.5%	6,323			5,559,825	19,167,604	2.18	
9	*Pioneer Trail PV Solar*												
10	Solar		15,237					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	15,237	27.5%	N/A	50.8%	N/A			N/A	N/A	N/A	
12	*Riviera 5*												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		825,660				6,588	5,439,645	1,000,000	5,439,645	18,825,385	2.28	3.46
15	Plant Unit Info	1,309	825,660	84.8%	93.9%	84.8%	6,588			5,439,645	18,825,385	2.28	
16	*Sanford 4*												
17	Gas		296,695				7,656	2,271,445	1,000,000	2,271,445	7,809,890	2.63	3.44
18	Plant Unit Info	1,070	296,695	37.3%	94.0%	72.8%	7,656			2,271,445	7,809,890	2.63	
19	*Sanford 5*												
20	Gas		317,924				7,591	2,413,207	1,000,000	2,413,207	8,292,612	2.61	3.44
21	Plant Unit Info	1,164	317,924	36.7%	45.6%	62.8%	7,591			2,413,207	8,292,612	2.61	
22	*Scherer 4*												
23	Coal		201,171					133,724	17,000,000	2,273,307	5,759,497	2.86	43.07
24	Plant Unit Info	625	201,171	43.3%	94.8%	43.3%	11,300			2,273,307	5,759,497	2.86	
25	*Space Coast*												
26	Solar		1,559					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10	1,559	21.0%	N/A	33.5%	N/A			N/A	N/A	N/A	
28	*St Lucie 1*												
29	Nuclear		711,664					7,540,994	1,000,000	7,540,994	3,660,399	0.51	0.49
30	Plant Unit Info	981	711,664	96.9%	96.9%	97.5%	10,596			7,540,994	3,660,399	0.51	
31	*St Lucie 2*												
32	Nuclear		609,290					6,325,749	1,000,000	6,325,749	3,155,916	0.52	0.50
33	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,382			6,325,749	3,155,916	0.52	
34	*Sunshine Gateway PV Solar*												
35	Solar		16,184					N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	16,184	28.5%	N/A	50.1%	N/A			N/A	N/A	N/A	
37	*Turkey Point 3*												
38	Nuclear		607,160					6,488,821	1,000,000	6,488,821	3,764,165	0.62	0.58
39	Plant Unit Info	837	607,160	97.5%	97.5%	97.5%	10,687			6,488,821	3,764,165	0.62	
40	*Turkey Point 4*												
41	Nuclear		595,553					6,563,143	1,000,000	6,563,143	3,280,259	0.55	0.50
42	Plant Unit Info	821	595,553	97.5%	97.5%	97.5%	11,020			6,563,143	3,280,259	0.55	
43	*Turkey Point 5*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		379,195				7,530	2,855,466	1,000,000	2,855,466	9,819,892	2.59	3.44
46	Plant Unit Info	1,210	379,195	42.1%	94.0%	69.9%	7,530			2,855,466	9,819,892	2.59	
47	*WCEC 01*												
48	Light Oil		0					0	0	0	0	0.00	0.00
49	Gas		860,612				6,540	5,628,184	1,000,000	5,628,184	18,971,331	2.20	3.37
50	Plant Unit Info	1,264	860,612	91.5%	93.9%	91.5%	6,540			5,628,184	18,971,331	2.20	
51	*WCEC 02*												
52	Light Oil		0					0	0	0	0	0.00	0.00
53	Gas		829,405				6,570	5,449,020	1,000,000	5,449,020	18,367,348	2.21	3.37
54	Plant Unit Info	1,264	829,405	88.2%	93.9%	88.2%	6,570			5,449,020	18,367,348	2.21	
55	*WCEC 03*												
56	Light Oil		0					0	0	0	0	0.00	0.00
57	Gas		835,373				6,607	5,518,995	1,000,000	5,518,995	18,603,249	2.23	3.37
58	Plant Unit Info	1,247	835,373	90.1%	93.9%	90.1%	6,607			5,518,995	18,603,249	2.23	
59	*Wildflower PV Solar*												
60	Solar		15,197					N/A	N/A	N/A	N/A	N/A	N/A
61	Plant Unit Info	74.5	15,197	27.4%	N/A	50.6%	N/A			N/A	N/A	N/A	
62	*System Totals*												
63	Plant Unit Info	26,848	12,055,416				7,594			91,543,565	233,413,813	1.94	
64													
65													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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 - 2019**												
2	*Babcock PV Solar*												
3	Solar		14,378					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,378	25.8%	N/A	41.5%	N/A			N/A	N/A	N/A	
5	*Barefoot PV Solar*												
6	Solar		15,044					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,044	27.1%	N/A	50.1%	N/A			N/A	N/A	N/A	
8	*Blue Cypress PV Solar*												
9	Solar		14,555					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,555	26.3%	N/A	48.5%	N/A			N/A	N/A	N/A	
11	*CCEC 3*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		635,062				6,577	4,176,799	1,000,000	4,176,799	14,257,995	2.25	3.41
14	Plant Unit Info	1,281	635,062	66.6%	70.2%	66.6%	6,577			4,176,799	14,257,995	2.25	
15	*Citrus PV Solar*												
16	Solar		14,646					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,646	25.8%	N/A	45.3%	N/A			N/A	N/A	N/A	
18	*Coral Farms PV Solar*												
19	Solar		15,345					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	15,345	27.7%	N/A	51.1%	N/A			N/A	N/A	N/A	
21	*Desoto Solar*												
22	Solar		4,337					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25	4,337	23.3%	N/A	40.0%	N/A			N/A	N/A	N/A	
24	*Fort Myers GT*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	96	0	0.0%	93.3%	0.0%	0			0	0	0.00	
28	*Fort Myers 2*												
29	Gas		840,703				7,063	5,938,103	1,000,000	5,938,103	20,262,952	2.41	3.41
30	Plant Unit Info	1,752	840,703	64.5%	94.0%	64.5%	7,063			5,938,103	20,262,952	2.41	
31	*Fort Myers 3A*												
32	Light Oil		530				14,301	1,300	5,830,000	7,580	122,897	23	95
33	Gas		21				14,301	300	1,000,000	300	1,018	4.85	3.39
34	Plant Unit Info	190	551	0.4%	93.5%	58.0%	14,301			7,880	123,915	22.49	
35	*Fort Myers 3B*												
36	Light Oil		509				13,055	1,140	5,830,000	6,645	107,738	21	95
37	Gas		23				13,055	300	1,000,000	300	1,018	4.43	3.39
38	Plant Unit Info	190	532	0.4%	93.5%	70.7%	13,055			6,945	108,756	20.44	
39	*Fort Myers 3C*												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		13,358				10,586	141,402	1,000,000	141,402	481,398	3.60	3.40
42	Plant Unit Info	215	13,358	8.4%	93.5%	92.7%	10,586			141,402	481,398	3.60	
43	*Fort Myers 3D*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		12,062				10,557	127,334	1,000,000	127,334	433,136	3.59	3.40
46	Plant Unit Info	215	12,062	7.5%	93.5%	93.5%	10,557			127,334	433,136	3.59	
47	*Hammock PV Solar*												
48	Solar		14,548					N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	74.5	14,548	26.3%	N/A	48.5%	N/A			N/A	N/A	N/A	
50	*Horizon PV Solar*												
51	Solar		15,348					N/A	N/A	N/A	N/A	N/A	N/A
52	Plant Unit Info	74.5	15,348	27.7%	N/A	51.1%	N/A			N/A	N/A	N/A	
53	*Indiantown FPL*												
54	Coal		0					0	0	0	0	0.00	0.00
55	Plant Unit Info		0	0.0%	0.0%	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Indian River PV Solar*												
2	Solar		14,505					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	14,505	26.2%	N/A	48.3%	N/A			N/A	N/A	N/A	
4	*Interstate PV Solar*												
5	Solar		15,149					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	15,149	27.0%	N/A	50.5%	N/A			N/A	N/A	N/A	
7	*Lauderdale GT*												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	57	0	0.0%	93.3%	0.0%	0			0	0	0.00	
11	*Lauderdale 6A*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		21,018				10,498	220,646	1,000,000	220,646	750,840	3.57	3.40
14	Plant Unit Info	215	21,018	13.1%	94.0%	94.0%	10,498			220,646	750,840	3.57	
15	*Lauderdale 6B*												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		18,795				10,512	197,579	1,000,000	197,579	672,593	3.58	3.40
18	Plant Unit Info	215	18,795	11.8%	94.0%	94.0%	10,512			197,579	672,593	3.58	
19	*Lauderdale 6C*												
20	Gas		20,816				10,500	218,576	1,000,000	218,576	744,094	3.57	3.40
21	Plant Unit Info	215	20,816	13.0%	94.0%	94.0%	10,500			218,576	744,094	3.57	
22	*Lauderdale 6D*												
23	Light Oil		405				15,180	1,055	5,830,000	6,148	81,504	20	77
24	Gas		0					0	0	0	0	0.00	0.00
25	Plant Unit Info	215	405	0.3%	94.0%	46.5%	15,180			6,148	81,504	20.12	
26	*Lauderdale 6E*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		0				0	0	0	0	0	0.00	0.00
29	Plant Unit Info	215	0	0.0%	94.0%	0.0%				0	0	0.00	
30	*Loggerhead PV Solar*												
31	Solar		14,532					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	14,532	26.2%	N/A	48.4%	N/A			N/A	N/A	N/A	
33	*Manatee 1*												
34	Heavy Oil		8,716					15,098	6,400,000	96,627	1,110,182	12.74	73.53
35	Gas		67,878				11,086	752,477	1,000,000	752,477	2,556,225	3.77	3.40
36	Plant Unit Info	790	76,594	13.1%	96.2%	34.1%	11,086			849,104	3,666,407	4.79	
37	*Manatee 2*												
38	Heavy Oil		5,798					10,125	6,400,000	64,797	744,476	12.84	73.53
39	Gas		70,566				11,176	788,642	1,000,000	788,642	2,675,435	3.79	3.39
40	Plant Unit Info	790	76,364	13.0%	96.2%	33.3%	11,176			853,439	3,419,911	4.48	
41	*Manatee 3*												
42	Gas		429,316				7,446	3,196,774	1,000,000	3,196,774	10,768,218	2.51	3.37
43	Plant Unit Info	1,238	429,316	46.6%	94.1%	75.6%	7,446			3,196,774	10,768,218	2.51	
44	*Manatee PV Solar*												
45	Solar		14,423					N/A	N/A	N/A	N/A	N/A	N/A
46	Plant Unit Info	74.5	14,423	25.8%	N/A	44.6%	N/A			N/A	N/A	N/A	
47	*Martin 3*												
48	Gas		99,479				8,569	852,407	1,000,000	852,407	2,898,144	2.91	3.40
49	Plant Unit Info	476	99,479	28.1%	93.9%	74.9%	8,569			852,407	2,898,144	2.91	
50	*Martin 4*												
51	Gas		93,970				8,638	811,754	1,000,000	811,754	2,757,732	2.93	3.40
52	Plant Unit Info	476	93,970	26.5%	94.0%	77.1%	8,638			811,754	2,757,732	2.93	
53	*Martin 8 Solar*												
54	Solar		11,873					N/A	N/A	N/A	N/A	N/A	N/A
55	Plant Unit Info	75	11,873	21.3%	N/A	39.3%	N/A			N/A	N/A	N/A	
56	*Martin 8*												
57	Light Oil		0					0	0	0	0	0.00	0.00
58	Gas		373,764				7,571	2,829,792	1,000,000	2,829,792	9,613,807	2.57	3.40
59	Plant Unit Info	1,231	373,764	40.8%	94.0%	79.3%	7,571			2,829,792	9,613,807	2.57	
60	*Miami-Dade PV Solar*												
61	Solar		14,793					N/A	N/A	N/A	N/A	N/A	N/A
62	Plant Unit Info	74.5	14,793	26.7%	N/A	49.3%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Okechobee 1*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		1,145,093				6,170	7,064,673	1,000,000	7,064,673	24,195,282	2.11	3.42
4	Plant Unit Info	1,652	1,145,093	93.2%	96.7%	93.2%	6,170			7,064,673	24,195,282	2.11	
5	*PEEC*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		879,466				6,323	5,560,605	1,000,000	5,560,605	18,991,730	2.16	3.42
8	Plant Unit Info	1,264	879,466	93.5%	93.9%	93.5%	6,323			5,560,605	18,991,730	2.16	
9	*Pioneer Trail PV Solar*												
10	Solar		15,117					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	15,117	27.0%	N/A	50.3%	N/A			N/A	N/A	N/A	
12	*Riviera 5*												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		826,705				6,585	5,444,142	1,000,000	5,444,142	18,657,854	2.26	3.43
15	Plant Unit Info	1,309	826,705	84.9%	93.9%	84.9%	6,585			5,444,142	18,657,854	2.26	
16	*Sanford 4*												
17	Gas		300,489				7,664	2,302,860	1,000,000	2,302,860	7,852,053	2.61	3.41
18	Plant Unit Info	1,070	300,489	37.7%	94.0%	75.5%	7,664			2,302,860	7,852,053	2.61	
19	*Sanford 5*												
20	Gas		377,468				7,501	2,831,504	1,000,000	2,831,504	9,658,469	2.56	3.41
21	Plant Unit Info	1,164	377,468	43.6%	94.0%	70.5%	7,501			2,831,504	9,658,469	2.56	
22	*Scherer 4*												
23	Coal		196,615					131,080	17,000,000	2,228,356	5,633,691	2.87	42.98
24	Plant Unit Info	625	196,615	42.3%	94.8%	42.3%	11,334			2,228,356	5,633,691	2.87	
25	*Space Coast*												
26	Solar		1,549					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10	1,549	20.8%	N/A	38.4%	N/A			N/A	N/A	N/A	
28	*St Lucie 1*												
29	Nuclear		711,664					7,540,994	1,000,000	7,540,994	3,660,399	0.51	0.49
30	Plant Unit Info	981	711,664	96.9%	96.9%	97.5%	10,596			7,540,994	3,660,399	0.51	
31	*St Lucie 2*												
32	Nuclear		609,290					6,325,749	1,000,000	6,325,749	3,155,916	0.52	0.50
33	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,382			6,325,749	3,155,916	0.52	
34	*Sunshine Gateway PV Solar*												
35	Solar		15,284					N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	15,284	27.0%	N/A	50.9%	N/A			N/A	N/A	N/A	
37	*Turkey Point 3*												
38	Nuclear		607,160					6,488,821	1,000,000	6,488,821	3,764,165	0.62	0.58
39	Plant Unit Info	837	607,160	97.5%	97.5%	97.5%	10,687			6,488,821	3,764,165	0.62	
40	*Turkey Point 4*												
41	Nuclear		595,553					6,563,143	1,000,000	6,563,143	3,280,259	0.55	0.50
42	Plant Unit Info	821	595,553	97.5%	97.5%	97.5%	11,020			6,563,143	3,280,259	0.55	
43	*Turkey Point 5*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		385,400				7,550	2,909,756	1,000,000	2,909,756	9,919,643	2.57	3.41
46	Plant Unit Info	1,210	385,400	42.8%	94.0%	74.1%	7,550			2,909,756	9,919,643	2.57	
47	*WCEC 01*												
48	Light Oil		0					0	0	0	0	0.00	0.00
49	Gas		861,848				6,539	5,635,316	1,000,000	5,635,316	18,815,365	2.18	3.34
50	Plant Unit Info	1,264	861,848	91.6%	93.9%	91.6%	6,539			5,635,316	18,815,365	2.18	
51	*WCEC 02*												
52	Light Oil		0					0	0	0	0	0.00	0.00
53	Gas		843,481				6,556	5,529,907	1,000,000	5,529,907	18,463,339	2.19	3.34
54	Plant Unit Info	1,264	843,481	89.7%	93.9%	89.7%	6,556			5,529,907	18,463,339	2.19	
55	*WCEC 03*												
56	Light Oil		0					0	0	0	0	0.00	0.00
57	Gas		833,215				6,608	5,505,930	1,000,000	5,505,930	18,383,286	2.21	3.34
58	Plant Unit Info	1,247	833,215	89.8%	93.9%	89.8%	6,608			5,505,930	18,383,286	2.21	
59	*Wildflower PV Solar*												
60	Solar		14,609					N/A	N/A	N/A	N/A	N/A	N/A
61	Plant Unit Info	74.5	14,609	26.4%	N/A	48.7%	N/A			N/A	N/A	N/A	
62	*System Totals*												
63	Plant Unit Info	26,848	12,126,271				7,617			92,366,437	235,472,852	1.94	
64													
65													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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 - 2019**												
2	*Babcock PV Solar*												
3	Solar		13,363					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,363	24.8%	N/A	46.0%	N/A			N/A	N/A	N/A	
5	*Barefoot PV Solar*												
6	Solar		13,981					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,981	26.1%	N/A	48.1%	N/A			N/A	N/A	N/A	
8	*Blue Cypress PV Solar*												
9	Solar		13,646					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,646	25.4%	N/A	47.0%	N/A			N/A	N/A	N/A	
11	*CCEC 3*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		828,183				6,525	5,403,771	1,000,000	5,403,771	18,679,140	2.26	3.46
14	Plant Unit Info	1,281	828,183	89.8%	93.9%	89.8%	6,525			5,403,771	18,679,140	2.26	
15	*Citrus PV Solar*												
16	Solar		13,663					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	13,663	24.8%	N/A	47.0%	N/A			N/A	N/A	N/A	
18	*Coral Farms PV Solar*												
19	Solar		13,885					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	13,885	25.9%	N/A	47.8%	N/A			N/A	N/A	N/A	
21	*Desoto Solar*												
22	Solar		3,878					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25	3,878	21.6%	N/A	39.8%	N/A			N/A	N/A	N/A	
24	*Fort Myers GT*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	96	0	0.0%	93.3%	0.0%	0			0	0	0.00	
28	*Fort Myers 2*												
29	Gas		688,186				7,185	4,944,713	1,000,000	4,944,713	17,090,822	2.48	3.46
30	Plant Unit Info	1,774	688,186	53.9%	77.3%	53.9%	7,185			4,944,713	17,090,822	2.48	
31	*Fort Myers 3A*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	*Fort Myers 3B*												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00
38	Plant Unit Info	190	0		93.5%					0	0	0.00	
39	*Fort Myers 3C*												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		3,819				10,574	40,382	1,000,000	40,382	140,007	3.67	3.47
42	Plant Unit Info	215	3,819	2.5%	93.5%	93.6%	10,574			40,382	140,007	3.67	
43	*Fort Myers 3D*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		3,216				10,540	33,896	1,000,000	33,896	117,338	3.65	3.46
46	Plant Unit Info	215	3,216	2.1%	93.5%	93.6%	10,540			33,896	117,338	3.65	
47	*Hammock PV Solar*												
48	Solar		13,698					N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	74.5	13,698	25.5%	N/A	47.2%	N/A			N/A	N/A	N/A	
50	*Horizon PV Solar*												
51	Solar		14,080					N/A	N/A	N/A	N/A	N/A	N/A
52	Plant Unit Info	74.5	14,080	26.3%	N/A	48.5%	N/A			N/A	N/A	N/A	
53	*Indiantown FPL*												
54	Coal		0					0	0	0	0	0.00	0.00
55	Plant Unit Info		0	0.0%	0.0%	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Indian River PV Solar*												
2	Solar		13,602					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	13,602	25.4%	N/A	46.8%	N/A			N/A	N/A	N/A	
4	*Interstate PV Solar*												
5	Solar		14,120					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	14,120	26.2%	N/A	48.6%	N/A			N/A	N/A	N/A	
7	*Lauderdale GT*												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	57	0	0.0%	93.3%	0.0%	0			0	0	0.00	
11	*Lauderdale 6A*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		6,063				10,538	63,890	1,000,000	63,890	221,571	3.65	3.47
14	Plant Unit Info	215	6,063	3.9%	94.0%	94.1%	10,538			63,890	221,571	3.65	
15	*Lauderdale 6B*												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		5,457				10,515	57,381	1,000,000	57,381	199,151	3.65	3.47
18	Plant Unit Info	215	5,457	3.5%	94.0%	94.1%	10,515			57,381	199,151	3.65	
19	*Lauderdale 6C*												
20	Gas		6,669				10,511	70,099	1,000,000	70,099	242,366	3.63	3.46
21	Plant Unit Info	215	6,669	4.3%	94.0%	94.0%	10,511			70,099	242,366	3.63	
22	*Lauderdale 6D*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		0					0	0	0	0	0.00	0.00
25	Plant Unit Info	215	0	0.0%	94.0%	0.0%	0			0	0	0.00	
26	*Lauderdale 6E*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		0					0	0	0	0	0.00	0.00
29	Plant Unit Info	215	0	0.0%	94.0%	0.0%	0			0	0	N/A	
30	*Loggerhead PV Solar*												
31	Solar		13,740					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	13,740	25.6%	N/A	47.3%	N/A			N/A	N/A	N/A	
33	*Manatee 1*												
34	Heavy Oil		0					0	0	0	0	0.00	0.00
35	Gas		2,090				16,100	33,649	1,000,000	33,649	114,266	5.47	3.40
36	Plant Unit Info	790	2,090	0.4%	96.2%	38.1%	16,100			33,649	114,266	5.47	
37	*Manatee 2*												
38	Heavy Oil		0					0	0	0	0	0.00	0.00
39	Gas		9,151				13,144	120,284	1,000,000	120,284	414,375	4.53	3.44
40	Plant Unit Info	790	9,151	1.6%	96.2%	32.2%	13,144			120,284	414,375	4.53	
41	*Manatee 3*												
42	Gas		420,574				7,435	3,127,005	1,000,000	3,127,005	10,645,181	2.53	3.40
43	Plant Unit Info	1,238	420,574	47.2%	94.1%	77.0%	7,435			3,127,005	10,645,181	2.53	
44	*Manatee PV Solar*												
45	Solar		13,709					N/A	N/A	N/A	N/A	N/A	N/A
46	Plant Unit Info	74.5	13,709	24.8%	N/A	47.2%	N/A			N/A	N/A	N/A	
47	*Martin 3*												
48	Gas		51,298				8,759	449,344	1,000,000	449,344	1,548,502	3.02	3.45
49	Plant Unit Info	476	51,298	15.0%	93.9%	73.8%	8,759			449,344	1,548,502	3.02	
50	*Martin 4*												
51	Gas		54,951				8,325	457,469	1,000,000	457,469	1,576,640	2.87	3.45
52	Plant Unit Info	476	54,951	16.0%	94.0%	73.5%	8,325			457,469	1,576,640	2.87	
53	*Martin 8 Solar*												
54	Solar		10,320					N/A	N/A	N/A	N/A	N/A	N/A
55	Plant Unit Info	75	10,320	19.1%	N/A	35.3%	N/A			N/A	N/A	N/A	
56	*Martin 8*												
57	Light Oil		0					0	0	0	0	0.00	0.00
58	Gas		359,343				7,605	2,732,667	1,000,000	2,732,667	9,392,848	2.61	3.44
59	Plant Unit Info	1,231	359,343	40.5%	94.0%	80.4%	7,605			2,732,667	9,392,848	2.61	
60	*Miami-Dade PV Solar*												
61	Solar		13,559					N/A	N/A	N/A	N/A	N/A	N/A
62	Plant Unit Info	74.5	13,559	25.3%	N/A	46.7%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Okechobee 1*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		906,001				6,191	5,608,907	1,000,000	5,608,907	19,518,222	2.15	3.48
4	Plant Unit Info	1,652	906,001	76.2%	78.9%	76.2%	6,191			5,608,907	19,518,222	2.15	
5	*PEEC*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		851,681				6,322	5,384,649	1,000,000	5,384,649	18,618,511	2.19	3.46
8	Plant Unit Info	1,264	851,681	93.6%	93.9%	93.6%	6,322			5,384,649	18,618,511	2.19	
9	*Pioneer Trail PV Solar*												
10	Solar		13,736					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	13,736	25.6%	N/A	47.3%	N/A			N/A	N/A	N/A	
12	*Riviera 5*												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		811,949				6,579	5,341,997	1,000,000	5,341,997	18,565,676	2.29	3.48
15	Plant Unit Info	1,309	811,949	86.1%	93.9%	86.1%	6,579			5,341,997	18,565,676	2.29	
16	*Sanford 4*												
17	Gas		241,363				7,642	1,844,443	1,000,000	1,844,443	6,373,797	2.64	3.46
18	Plant Unit Info	1,070	241,363	31.3%	94.0%	71.6%	7,642			1,844,443	6,373,797	2.64	
19	*Sanford 5*												
20	Gas		333,507				7,566	2,523,198	1,000,000	2,523,198	8,711,992	2.61	3.45
21	Plant Unit Info	1,164	333,507	39.8%	94.0%	71.3%	7,566			2,523,198	8,711,992	2.61	
22	*Scherer 4*												
23	Coal		180,826					121,362	17,000,000	2,063,155	5,199,752	2.88	42.84
24	Plant Unit Info	625	180,826	40.2%	94.8%	40.2%	11,410			2,063,155	5,199,752	2.88	
25	*Space Coast*												
26	Solar		1,425					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10	1,425	19.8%	N/A	36.5%	N/A			N/A	N/A	N/A	
28	*St Lucie 1*												
29	Nuclear		688,707					7,297,736	1,000,000	7,297,736	3,542,321	0.51	0.49
30	Plant Unit Info	981	688,707	96.9%	96.9%	97.5%	10,596			7,297,736	3,542,321	0.51	
31	*St Lucie 2*												
32	Nuclear		589,635					6,121,692	1,000,000	6,121,692	3,054,112	0.52	0.50
33	Plant Unit Info	840	589,635	97.5%	97.5%	97.5%	10,382			6,121,692	3,054,112	0.52	
34	*Sunshine Gateway PV Solar*												
35	Solar		14,196					N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	14,196	26.2%	N/A	48.9%	N/A			N/A	N/A	N/A	
37	*Turkey Point 3*												
38	Nuclear		587,574					6,279,505	1,000,000	6,279,505	3,642,741	0.62	0.58
39	Plant Unit Info	837	587,574	97.5%	97.5%	97.5%	10,687			6,279,505	3,642,741	0.62	
40	*Turkey Point 4*												
41	Nuclear		576,342					6,351,428	1,000,000	6,351,428	3,174,444	0.55	0.50
42	Plant Unit Info	821	576,342	97.5%	97.5%	97.5%	11,020			6,351,428	3,174,444	0.55	
43	*Turkey Point 5*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		339,189				7,586	2,573,222	1,000,000	2,573,222	8,883,753	2.62	3.45
46	Plant Unit Info	1,210	339,189	38.9%	94.0%	72.6%	7,586			2,573,222	8,883,753	2.62	
47	*WCEC 01*												
48	Light Oil		0					0	0	0	0	0.00	0.00
49	Gas		832,886				6,540	5,447,023	1,000,000	5,447,023	18,459,611	2.22	3.39
50	Plant Unit Info	1,264	832,886	91.5%	93.9%	91.5%	6,540			5,447,023	18,459,611	2.22	
51	*WCEC 02*												
52	Light Oil		0					0	0	0	0	0.00	0.00
53	Gas		794,662				6,576	5,225,379	1,000,000	5,225,379	17,708,642	2.23	3.39
54	Plant Unit Info	1,264	794,662	87.3%	93.9%	87.3%	6,576			5,225,379	17,708,642	2.23	
55	*WCEC 03*												
56	Light Oil		0					0	0	0	0	0.00	0.00
57	Gas		807,345				6,608	5,334,618	1,000,000	5,334,618	18,078,745	2.24	3.39
58	Plant Unit Info	1,247	807,345	89.9%	93.9%	89.9%	6,608			5,334,618	18,078,745	2.24	
59	*Wildflower PV Solar*												
60	Solar		14,044					N/A	N/A	N/A	N/A	N/A	N/A
61	Plant Unit Info	74.5	14,044	26.2%	N/A	48.3%	N/A			N/A	N/A	N/A	
62	*System Totals*												
63	Plant Unit Info	26,870	11,203,312				7,581			84,931,503	213,914,527	1.91	
64													
65													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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 - 2019**												
2	*Babcock PV Solar*												
3	Solar		13,976					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,976	25.2%	N/A	46.6%	N/A			N/A	N/A	N/A	
5	*Barefoot PV Solar*												
6	Solar		14,333					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,333	25.9%	N/A	51.7%	N/A			N/A	N/A	N/A	
8	*Blue Cypress PV Solar*												
9	Solar		13,867					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,867	25.0%	N/A	50.0%	N/A			N/A	N/A	N/A	
11	*CCEC 3*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		740,102				6,604	4,887,396	1,000,000	4,887,396	17,576,675	2.37	3.60
14	Plant Unit Info	1,281	740,102	77.6%	93.9%	77.6%	6,604			4,887,396	17,576,675	2.37	
15	*Citrus PV Solar*												
16	Solar		14,080					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,080	25.4%	N/A	46.9%	N/A			N/A	N/A	N/A	
18	*Coral Farms PV Solar*												
19	Solar		14,256					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	14,256	25.7%	N/A	51.4%	N/A			N/A	N/A	N/A	
21	*Desoto Solar*												
22	Solar		3,843					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25	3,843	20.7%	N/A	41.3%	N/A			N/A	N/A	N/A	
24	*Fort Myers GT*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	96	0	0.0%	93.3%	0.0%	0			0	0	0.00	
28	*Fort Myers 2*												
29	Gas		769,570				7,215	5,552,341	1,000,000	5,552,341	19,966,232	2.59	3.60
30	Plant Unit Info	1,774	769,570	58.3%	85.9%	58.3%	7,215			5,552,341	19,966,232	2.59	
31	*Fort Myers 3A*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	*Fort Myers 3B*												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00
38	Plant Unit Info	190	0	0.0%	93.5%	0.0%	0			0	0	0.00	
39	*Fort Myers 3C*												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		1,005				10,558	10,611	1,000,000	10,611	38,085	3.79	3.59
42	Plant Unit Info	215	1,005	0.6%	93.5%	93.7%	10,558			10,611	38,085	3.79	
43	*Fort Myers 3D*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		1,005				10,558	10,611	1,000,000	10,611	38,085	3.79	3.59
46	Plant Unit Info	215	1,005	0.6%	93.5%	93.7%	10,558			10,611	38,085	3.79	
47	*Hammock PV Solar*												
48	Solar		14,573					N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	74.5	14,573	26.3%	N/A	52.6%	N/A			N/A	N/A	N/A	
50	*Horizon PV Solar*												
51	Solar		14,401					N/A	N/A	N/A	N/A	N/A	N/A
52	Plant Unit Info	74.5	14,401	26.0%	N/A	52.0%	N/A			N/A	N/A	N/A	
53	*Indiantown FPL*												
54	Coal		0					0	0	0	0	0.00	0.00
55	Plant Unit Info		0	0.0%	0.0%	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Indian River PV Solar*												
2	Solar		13,822					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	13,822	24.9%	N/A	49.9%	N/A			N/A	N/A	N/A	
4	*Interstate PV Solar*												
5	Solar		14,282					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	14,282	25.7%	N/A	51.5%	N/A			N/A	N/A	N/A	
7	*Lauderdale GT*												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	57	0	0.0%	93.3%	0.0%	0			0	0	0.00	
11	*Lauderdale 6A*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		4,850				10,551	51,172	1,000,000	51,172	184,968	3.81	3.61
14	Plant Unit Info	215	4,850	3.0%	94.0%	93.9%	10,551			51,172	184,968	3.81	
15	*Lauderdale 6B*												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		3,840				10,553	40,524	1,000,000	40,524	145,726	3.79	3.60
18	Plant Unit Info	215	3,840	2.4%	94.0%	94.0%	10,553			40,524	145,726	3.79	
19	*Lauderdale 6C*												
20	Gas		3,032				10,536	31,945	1,000,000	31,945	114,935	3.79	3.60
21	Plant Unit Info	215	3,032	1.9%	94.0%	94.2%	10,536			31,945	114,935	3.79	
22	*Lauderdale 6D*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		0					0	0	0	0	0.00	0.00
25	Plant Unit Info	215	0	0.0%	94.0%	0.0%	0			0	0	0.00	
26	*Lauderdale 6E*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		0					0	0	0	0	0.00	0.00
29	Plant Unit Info	215	0	0.0%	94.0%	0.0%	0			0	0	0.00	
30	*Loggerhead PV Solar*												
31	Solar		14,138					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	14,138	25.5%	N/A	51.0%	N/A			N/A	N/A	N/A	
33	*Manatee 1*												
34	Heavy Oil		0					0	0	0	0	0.00	0.00
35	Gas		2,148				15,921	34,197	1,000,000	34,197	122,029	5.68	3.57
36	Plant Unit Info	790	2,148	0.4%	96.2%	39.3%	15,921			34,197	122,029	5.68	
37	*Manatee 2*												
38	Heavy Oil		0					0	0	0	0	0.00	0.00
39	Gas		4,168				13,241	55,188	1,000,000	55,188	197,109	4.73	3.57
40	Plant Unit Info	790	4,168	0.7%	96.2%	37.7%	13,241			55,188	197,109	4.73	
41	*Manatee 3*												
42	Gas		456,377				7,409	3,381,314	1,000,000	3,381,314	12,002,316	2.63	3.55
43	Plant Unit Info	1,238	456,377	49.6%	94.1%	75.1%	7,409			3,381,314	12,002,316	2.63	
44	*Manatee PV Solar*												
45	Solar		14,505					N/A	N/A	N/A	N/A	N/A	N/A
46	Plant Unit Info	74.5	14,505	25.4%	N/A	48.3%	N/A			N/A	N/A	N/A	
47	*Martin 3*												
48	Gas		54,802				8,726	478,178	1,000,000	478,178	1,717,093	3.13	3.59
49	Plant Unit Info	476	54,802	15.5%	93.9%	78.8%	8,726			478,178	1,717,093	3.13	
50	*Martin 4*												
51	Gas		50,631				8,744	442,724	1,000,000	442,724	1,590,382	3.14	3.59
52	Plant Unit Info	476	50,631	14.3%	94.0%	79.4%	8,744			442,724	1,590,382	3.14	
53	*Martin 8 Solar*												
54	Solar		9,114					N/A	N/A	N/A	N/A	N/A	N/A
55	Plant Unit Info	75	9,114	16.3%	N/A	30.1%	N/A			N/A	N/A	N/A	
56	*Martin 8*												
57	Light Oil		0					0	0	0	0	0.00	0.00
58	Gas		437,237				7,544	3,298,487	1,000,000	3,298,487	11,799,968	2.70	3.58
59	Plant Unit Info	1,231	437,237	47.7%	94.0%	79.3%	7,544			3,298,487	11,799,968	2.70	
60	*Miami-Dade PV Solar*												
61	Solar		14,012					N/A	N/A	N/A	N/A	N/A	N/A
62	Plant Unit Info	74.5	14,012	25.3%	N/A	50.6%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Okechobee 1*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		728,893				6,233	4,543,205	1,000,000	4,543,205	16,520,048	2.27	3.64
4	Plant Unit Info	1,652	728,893	59.3%	63.4%	59.3%	6,233			4,543,205	16,520,048	2.27	
5	*PEEC*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		853,307				6,344	5,413,286	1,000,000	5,413,286	19,467,487	2.28	3.60
8	Plant Unit Info	1,264	853,307	90.7%	93.9%	90.7%	6,344			5,413,286	19,467,487	2.28	
9	*Pioneer Trail PV Solar*												
10	Solar		13,647					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	13,647	24.6%	N/A	49.2%	N/A			N/A	N/A	N/A	
12	*Riviera 5*												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		708,062				6,656	4,713,202	1,000,000	4,713,202	17,071,355	2.41	3.62
15	Plant Unit Info	1,309	708,062	72.7%	93.9%	72.7%	6,656			4,713,202	17,071,355	2.41	
16	*Sanford 4*												
17	Gas		301,083				7,718	2,323,641	1,000,000	2,323,641	8,354,020	2.77	3.60
18	Plant Unit Info	1,070	301,083	37.8%	94.0%	74.8%	7,718			2,323,641	8,354,020	2.77	
19	*Sanford 5*												
20	Gas		346,963				7,647	2,653,342	1,000,000	2,653,342	9,538,242	2.75	3.59
21	Plant Unit Info	1,164	346,963	40.1%	94.0%	75.7%	7,647			2,653,342	9,538,242	2.75	
22	*Scherer 4*												
23	Coal		188,812					126,530	17,000,000	2,151,018	5,401,930	2.86	42.69
24	Plant Unit Info	625	188,812	40.6%	94.8%	40.6%	11,392			2,151,018	5,401,930	2.86	
25	*Space Coast*												
26	Solar		1,455					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10	1,455	18.7%	N/A	39.1%	N/A			N/A	N/A	N/A	
28	*St Lucie 1*												
29	Nuclear		298,439					3,162,353	1,000,000	3,162,353	1,535,005	0.51	0.49
30	Plant Unit Info	981	298,439	40.6%	40.6%	97.5%	10,596			3,162,353	1,535,005	0.51	
31	*St Lucie 2*												
32	Nuclear		609,290					6,325,749	1,000,000	6,325,749	3,155,916	0.52	0.50
33	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,382			6,325,749	3,155,916	0.52	
34	*Sunshine Gateway PV Solar*												
35	Solar		14,338					N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	14,338	25.7%	N/A	56.4%	N/A			N/A	N/A	N/A	
37	*Turkey Point 3*												
38	Nuclear		607,160					6,488,821	1,000,000	6,488,821	3,764,165	0.62	0.58
39	Plant Unit Info	837	607,160	97.5%	97.5%	97.5%	10,687			6,488,821	3,764,165	0.62	
40	*Turkey Point 4*												
41	Nuclear		595,553					6,563,143	1,000,000	6,563,143	3,280,259	0.55	0.50
42	Plant Unit Info	821	595,553	97.5%	97.5%	97.5%	11,020			6,563,143	3,280,259	0.55	
43	*Turkey Point 5*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		57,713				7,330	423,053	1,000,000	423,053	1,520,892	2.64	3.60
46	Plant Unit Info	1,210	57,713	6.4%	6.9%	64.4%	7,330			423,053	1,520,892	2.64	
47	*WCEC 01*												
48	Light Oil		0					0	0	0	0	0.00	0.00
49	Gas		817,457				6,581	5,379,621	1,000,000	5,379,621	19,062,637	2.33	3.54
50	Plant Unit Info	1,264	817,457	86.9%	93.9%	86.9%	6,581			5,379,621	19,062,637	2.33	
51	*WCEC 02*												
52	Light Oil		0					0	0	0	0	0.00	0.00
53	Gas		778,504				6,620	5,153,528	1,000,000	5,153,528	18,262,158	2.35	3.54
54	Plant Unit Info	1,264	778,504	82.8%	93.9%	82.8%	6,620			5,153,528	18,262,158	2.35	
55	*WCEC 03*												
56	Light Oil		0					0	0	0	0	0.00	0.00
57	Gas		800,408				6,647	5,320,265	1,000,000	5,320,265	18,852,416	2.36	3.54
58	Plant Unit Info	1,247	800,408	86.3%	93.9%	86.3%	6,647			5,320,265	18,852,416	2.36	
59	*Wildflower PV Solar*												
60	Solar		14,678					N/A	N/A	N/A	N/A	N/A	N/A
61	Plant Unit Info	74.5	14,678	26.5%	N/A	53.0%	N/A			N/A	N/A	N/A	
62	*System Totals*												
63	Plant Unit Info	26,870	10,447,731				7,551			78,888,914	211,280,134	2.02	
64													
65													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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 - 2019**												
2	*Babcock PV Solar*												
3	Solar		12,679					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,679	23.6%	N/A	47.3%	N/A			N/A	N/A	N/A	
5	*Barefoot PV Solar*												
6	Solar		12,772					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,772	23.8%	N/A	51.9%	N/A			N/A	N/A	N/A	
8	*Blue Cypress PV Solar*												
9	Solar		12,499				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,499	23.3%	N/A	50.8%	N/A			N/A	N/A	N/A	
11	*CCEC 3*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		504,581				6,669	3,365,112	1,000,000	3,365,112	13,290,682	2.63	3.95
14	Plant Unit Info	1,277	504,581	54.9%	66.1%	54.9%	6,669			3,365,112	13,290,682	2.63	
15	*Citrus PV Solar*												
16	Solar		12,601					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	12,601	23.5%	N/A	47.0%	N/A			N/A	N/A	N/A	
18	*Coral Farms PV Solar*												
19	Solar		12,549					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	12,549	23.4%	N/A	51.0%	N/A			N/A	N/A	N/A	
21	*Desoto Solar*												
22	Solar		3,270					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25	3,270	18.2%	N/A	39.6%	N/A			N/A	N/A	N/A	
24	*Fort Myers GT*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	99	0	0.0%	93.3%	0.0%	0			0	0	0.00	
28	*Fort Myers 2*												
29	Gas		656,162				7,232	4,745,581	1,000,000	4,745,581	18,738,519	2.86	3.95
30	Plant Unit Info	1,791	656,162	50.9%	85.1%	50.9%	7,232			4,745,581	18,738,519	2.86	
31	*Fort Myers 3A*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	195	0		70.2%		0			0	0	0.00	
35	*Fort Myers 3B*												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00
38	Plant Unit Info	195	0		93.5%		0			0	0	0.00	
39	*Fort Myers 3C*												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		0					0	0	0	0	0.00	0.00
42	Plant Unit Info	213	0	0.0%	93.5%	0	0			0	0	0.00	
43	*Fort Myers 3D*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		0					0	0	0	0	0.00	0.00
46	Plant Unit Info	213	0	0.0%	93.5%	0.0%	0			0	0	0.00	
47	*Hammock PV Solar*												
48	Solar		13,348					N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	74.5	13,348	24.9%	N/A	54.3%	N/A			N/A	N/A	N/A	
50	*Horizon PV Solar*												
51	Solar		12,661					N/A	N/A	N/A	N/A	N/A	N/A
52	Plant Unit Info	74.5	12,661	23.6%	N/A	51.5%	N/A			N/A	N/A	N/A	
53	*Indiantown FPL*												
54	Coal		0					0	0	0	0	0.00	0.00
55	Plant Unit Info		0	0.0%	0.0%	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Indian River PV Solar*												
2	Solar		12,457					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	12,457	23.2%	N/A	50.7%	N/A			N/A	N/A	N/A	
4	*Interstate PV Solar*												
5	Solar		12,464					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	12,464	23.2%	N/A	50.7%	N/A			N/A	N/A	N/A	
7	*Lauderdale GT*												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	59	0	0.0%	93.3%	0.0%	0			0	0	0.00	
11	*Lauderdale 6A*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		1,001				10,634	10,645	1,000,000	10,645	41,996	4.20	3.95
14	Plant Unit Info	213	1,001	0.7%	94.0%	93.6%	10,634			10,645	41,996	4.20	
15	*Lauderdale 6B*												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		1,402				10,544	14,783	1,000,000	14,783	58,320	4.16	3.95
18	Plant Unit Info	213	1,402	0.9%	94.0%	93.6%	10,544			14,783	58,320	4.16	
19	*Lauderdale 6C*												
20	Gas		2,002				10,634	21,289	1,000,000	21,289	83,990	4.20	3.95
21	Plant Unit Info	213	2,002	1.3%	94.0%	94.3%	10,634			21,289	83,990	4.20	
22	*Lauderdale 6D*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		0					0	0	0	0	0.00	0.00
25	Plant Unit Info	213	0	0.0%	94.0%	0.0%	0			0	0	0.00	
26	*Lauderdale 6E*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		0					0	0	0	0	0.00	
29	Plant Unit Info	213	0	0.0%	94.0%	0.0%	0			0	0	0.00	
30	*Loggerhead PV Solar*												
31	Solar		12,637					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	12,637	23.6%	N/A	51.4%	N/A			N/A	N/A	N/A	
33	*Manatee 1*												
34	Heavy Oil		0					0	0	0	0	0.00	0.00
35	Gas		0					0	0	0	0	0.00	
36	Plant Unit Info	795	0	0.0%	96.2%	0.0%	0			0	0	0.00	
37	*Manatee 2*												
38	Heavy Oil		0					0	0	0	0	0.00	0.00
39	Gas		2,122				16,131	34,230	1,000,000	34,230	134,487	6.34	3.93
40	Plant Unit Info	795	2,122	0.4%	96.2%	38.1%	16,131			34,230	134,487	6.34	
41	*Manatee 3*												
42	Gas		203,004				7,677	1,558,532	1,000,000	1,558,532	6,130,808	3.02	3.93
43	Plant Unit Info	1,251	203,004	22.5%	70.8%	55.2%	7,677			1,558,532	6,130,808	3.02	
44	*Manatee PV Solar*												
45	Solar		12,743					N/A	N/A	N/A	N/A	N/A	N/A
46	Plant Unit Info	74.5	12,743	23.8%	N/A	47.5%	N/A			N/A	N/A	N/A	
47	*Martin 3*												
48	Gas		14,937				8,420	125,778	1,000,000	125,778	494,427	3.31	3.93
49	Plant Unit Info	489	14,937	4.2%	93.9%	53.6%	8,420			125,778	494,427	3.31	
50	*Martin 4*												
51	Gas		14,872				8,761	130,292	1,000,000	130,292	512,578	3.45	3.93
52	Plant Unit Info	489	14,872	4.2%	94.0%	74.1%	8,761			130,292	512,578	3.45	
53	*Martin 8 Solar*												
54	Solar		6,510					N/A	N/A	N/A	N/A	N/A	N/A
55	Plant Unit Info	75	6,510	12.1%	N/A	20.7%	N/A			N/A	N/A	N/A	
56	*Martin 8*												
57	Light Oil		0					0	0	0	0	0.00	0.00
58	Gas		240,741				7,630	1,836,966	1,000,000	1,836,966	7,217,022	3.00	3.93
59	Plant Unit Info	1,246	240,741	26.8%	94.0%	74.3%	7,630			1,836,966	7,217,022	3.00	
60	*Miami-Dade PV Solar*												
61	Solar		13,100					N/A	N/A	N/A	N/A	N/A	N/A
62	Plant Unit Info	74.5	13,100	23.8%	N/A	53.3%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Okechobee 1*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		714,991				6,182	4,420,164	1,000,000	4,420,164	17,561,736	2.46	3.97
4	Plant Unit Info	1,638	714,991	60.6%	63.4%	60.6%	6,182			4,420,164	17,561,736	2.46	
5	*PEEC*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		837,247				6,332	5,301,206	1,000,000	5,301,206	20,936,074	2.50	3.95
8	Plant Unit Info	1,251	837,247	93.0%	93.9%	93.0%	6,332			5,301,206	20,936,074	2.50	
9	*Pioneer Trail PV Solar*												
10	Solar		12,118					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	12,118	22.6%	N/A	49.3%	N/A			N/A	N/A	N/A	
12	*Riviera 5*												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		721,230				6,622	4,776,156	1,000,000	4,776,156	18,850,998	2.61	3.95
15	Plant Unit Info	1,307	721,230	76.6%	93.9%	76.6%	6,622			4,776,156	18,850,998	2.61	
16	*Sanford 4*												
17	Gas		130,433				7,646	997,245	1,000,000	997,245	3,934,297	3.02	3.95
18	Plant Unit Info	1,088	130,433	16.6%	94.0%	68.1%	7,646			997,245	3,934,297	3.02	
19	*Sanford 5*												
20	Gas		241,154				7,624	1,838,622	1,000,000	1,838,622	7,253,667	3.01	3.95
21	Plant Unit Info	1,180	241,154	28.4%	94.0%	65.1%	7,624			1,838,622	7,253,667	3.01	
22	*Scherer 4*												
23	Coal		176,857					118,856	17,000,000	2,020,550	5,070,481	2.87	42.66
24	Plant Unit Info	626	176,857	39.2%	94.8%	39.2%	11,425			2,020,550	5,070,481	2.87	
25	*Space Coast*												
26	Solar		1,258					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10	1,258	16.5%	N/A	34.9%	N/A			N/A	N/A	N/A	
28	*St Lucie 1*												
29	Nuclear		328,810					3,476,970	1,000,000	3,476,970	1,628,265	0.50	0.47
30	Plant Unit Info	1,003	328,810	45.2%	45.2%	97.5%	10,574			3,476,970	1,628,265	0.50	
31	*St Lucie 2*												
32	Nuclear		603,235					6,250,824	1,000,000	6,250,824	3,118,536	0.52	0.50
33	Plant Unit Info	860	603,235	97.5%	97.5%	97.5%	10,362			6,250,824	3,118,536	0.52	
34	*Sunshine Gateway PV Solar*												
35	Solar		12,693					N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	12,693	23.7%	N/A	51.6%	N/A			N/A	N/A	N/A	
37	*Turkey Point 3*												
38	Nuclear		603,018					6,483,318	1,000,000	6,483,318	3,760,973	0.62	0.58
39	Plant Unit Info	859	603,018	97.5%	97.5%	97.5%	10,751			6,483,318	3,760,973	0.62	
40	*Turkey Point 4*												
41	Nuclear		595,296					6,547,207	1,000,000	6,547,207	3,272,294	0.55	0.50
42	Plant Unit Info	848	595,296	97.5%	97.5%	97.5%	10,998			6,547,207	3,272,294	0.55	
43	*Turkey Point 5*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		0					0	0	0	0	0.00	
46	Plant Unit Info	1,227	0	0.0%	0.0%	0.0%	0			0	0	0.00	
47	*WCEC 01*												
48	Light Oil		0					0	0	0	0	0.00	0.00
49	Gas		649,446				6,578	4,272,130	1,000,000	4,272,130	16,788,262	2.59	3.93
50	Plant Unit Info	1,267	649,446	71.2%	77.2%	71.2%	6,578			4,272,130	16,788,262	2.59	
51	*WCEC 02*												
52	Light Oil		0					0	0	0	0	0.00	0.00
53	Gas		752,576				6,606	4,971,840	1,000,000	4,971,840	19,542,593	2.60	3.93
54	Plant Unit Info	1,267	752,576	82.5%	93.9%	82.5%	6,606			4,971,840	19,542,593	2.60	
55	*WCEC 03*												
56	Light Oil		0					0	0	0	0	0.00	0.00
57	Gas		735,592				6,715	4,939,320	1,000,000	4,939,320	19,414,299	2.64	3.93
58	Plant Unit Info	1,242	735,592	82.3%	93.9%	82.3%	6,715			4,939,320	19,414,299	2.64	
59	*Wildflower PV Solar*												
60	Solar		13,149					N/A	N/A	N/A	N/A	N/A	N/A
61	Plant Unit Info	74.5	13,149	24.5%	N/A	53.5%	N/A			N/A	N/A	N/A	
62	*System Totals*												
63	Plant Unit Info	27,063	8,932,217				7,628			68,138,760	187,835,304	2.10	
64													
65													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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 - 2019**												
2	*Babcock PV Solar*												
3	Solar		11,816					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	11,816	21.3%	N/A	46.5%	N/A			N/A	N/A	N/A	
5	*Barefoot PV Solar*												
6	Solar		11,641					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	11,641	21.0%	N/A	45.8%	N/A			N/A	N/A	N/A	
8	*Blue Cypress PV Solar*												
9	Solar		11,501					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	11,501	20.8%	N/A	45.3%	N/A			N/A	N/A	N/A	
11	*CCEC 3*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		527,780				6,685	3,528,372	1,000,000	3,528,372	15,183,810	2.88	4.30
14	Plant Unit Info	1,307	527,780	54.3%	73.5%	54.3%	6,685			3,528,372	15,183,810	2.88	
15	*Citrus PV Solar*												
16	Solar		11,786					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	11,786	21.3%	N/A	46.4%	N/A			N/A	N/A	N/A	
18	*Coral Farms PV Solar*												
19	Solar		11,468					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	11,468	20.7%	N/A	45.1%	N/A			N/A	N/A	N/A	
21	*Desoto Solar*												
22	Solar		2,914					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25	2,914	15.7%	N/A	34.2%	N/A			N/A	N/A	N/A	
24	*Fort Myers GT*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	99	0	0.0%	93.3%	0.0%	0			0	0	0.00	
28	*Fort Myers 2*												
29	Gas		615,475				7,349	4,523,237	1,000,000	4,523,237	19,465,060	3.16	4.30
30	Plant Unit Info	1,791	615,475	46.2%	83.8%	46.2%	7,349			4,523,237	19,465,060	3.16	
31	*Fort Myers 3A*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	195	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	*Fort Myers 3B*												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00
38	Plant Unit Info	195	0	0.0%	70.9%	0.0%	0			0	0	0.00	
39	*Fort Myers 3C*												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		0					0	0	0	0	0.00	0.00
42	Plant Unit Info	213	0	0.0%	93.5%	0.0%	0			0	0	0.00	
43	*Fort Myers 3D*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		0					0	0	0	0	0.00	0.00
46	Plant Unit Info	213	0	0.0%	93.5%	0.0%	0			0	0	0.00	
47	*Hammock PV Solar*												
48	Solar		12,265					N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	74.5	12,265	22.1%	N/A	48.3%	N/A			N/A	N/A	N/A	
50	*Horizon PV Solar*												
51	Solar		11,553					N/A	N/A	N/A	N/A	N/A	N/A
52	Plant Unit Info	74.5	11,553	20.8%	N/A	45.5%	N/A			N/A	N/A	N/A	
53	*Indiantown FPL*												
54	Coal		0					0	0	0	0	0.00	0.00
55	Plant Unit Info		0	0.0%	0.0%	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Indian River PV Solar*												
2	Solar		11,462					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	11,462	20.7%	N/A	45.1%	N/A			N/A	N/A	N/A	
4	*Interstate PV Solar*												
5	Solar		11,648					N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	74.5	11,648	21.0%	N/A	45.8%	N/A			N/A	N/A	N/A	
7	*Lauderdale GT*												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	59	0	0.0%	93.3%	0.0%	0			0	0	0.00	
11	*Lauderdale 6A*												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		0					0	0	0	0	0.00	0.00
14	Plant Unit Info	213	0	0.0%	94.0%	0.0%	0			0	0	0.00	
15	*Lauderdale 6B*												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		0					0	0	0	0	0.00	0.00
18	Plant Unit Info	213	0	0.0%	94.0%	0.0%	0			0	0	0.00	
19	*Lauderdale 6C*												
20	Gas		0					0	0	0	0	0.00	0.00
21	Plant Unit Info	213	0	0.0%	94.0%	0.0%	0			0	0	0.00	
22	*Lauderdale 6D*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		0					0	0	0	0	0.00	0.00
25	Plant Unit Info	213	0	0.0%	94.0%	0.0%	0			0	0	0.00	
26	*Lauderdale 6E*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		0					0	0	0	0	0.00	0.00
29	Plant Unit Info	213	0	0.0%	94.0%	0.0%	0			0	0	0.00	
30	*Loggerhead PV Solar*												
31	Solar		11,746					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	11,746	21.2%	N/A	46.2%	N/A			N/A	N/A	N/A	
33	*Manatee 1*												
34	Heavy Oil		0					0	0	0	0	0.00	0.00
35	Gas		0					0	0	0	0	0.00	0.00
36	Plant Unit Info	795	0	0.0%	96.2%	0.0%	0			0	0	0.00	
37	*Manatee 2*												
38	Heavy Oil		0					0	0	0	0	0.00	0.00
39	Gas		0					0	0	0	0	0.00	0.00
40	Plant Unit Info	795	0	0.0%	96.2%	0.0%	0			0	0	0.00	
41	*Manatee 3*												
42	Gas		93,533				8,114	758,934	1,000,000	758,934	3,248,553	3.47	4.28
43	Plant Unit Info	1,251	93,533	10.1%	60.2%	61.8%	8,114			758,934	3,248,553	3.47	
44	*Manatee PV Solar*												
45	Solar		11,778					N/A	N/A	N/A	N/A	N/A	N/A
46	Plant Unit Info	74.5	11,778	21.3%	N/A	46.4%	N/A			N/A	N/A	N/A	
47	*Martin 3*												
48	Gas		1,587				11,334	17,987	1,000,000	17,987	76,992	4.85	4.28
49	Plant Unit Info	489	1,587	0.4%	61.6%	65.5%	11,334			17,987	76,992	4.85	
50	*Martin 4*												
51	Gas		8,680				9,763	84,747	1,000,000	84,747	362,749	4.18	4.28
52	Plant Unit Info	489	8,680	2.4%	55.3%	61.3%	9,763			84,747	362,749	4.18	
53	*Martin 8 Solar*												
54	Solar		5,425					N/A	N/A	N/A	N/A	N/A	N/A
55	Plant Unit Info	75	5,425	9.7%	N/A	17.9%	N/A			N/A	N/A	N/A	
56	*Martin 8*												
57	Light Oil		0					0	0	0	0	0.00	0.00
58	Gas		145,686				8,138	1,185,598	1,000,000	1,185,598	5,075,116	3.48	4.28
59	Plant Unit Info	1,246	145,686	15.7%	94.0%	68.4%	8,138			1,185,598	5,075,116	3.48	
60	*Miami-Dade PV Solar*												
61	Solar		12,454					N/A	N/A	N/A	N/A	N/A	N/A
62	Plant Unit Info	74.5	12,454	21.2%	N/A	49.0%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	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	*Okechobee 1*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		1,028,007				6,133	6,305,257	1,000,000	6,305,257	27,319,165	2.66	4.33
4	Plant Unit Info	1,638	1,028,007	84.4%	91.3%	84.4%	6,133			6,305,257	27,319,165	2.66	
5	*PEEC*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		862,214				6,334	5,461,148	1,000,000	5,461,148	23,501,218	2.73	4.30
8	Plant Unit Info	1,251	862,214	92.6%	93.9%	92.6%	6,334			5,461,148	23,501,218	2.73	
9	*Pioneer Trail PV Solar*												
10	Solar		11,232					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	74.5	11,232	20.3%	N/A	44.2%	N/A			N/A	N/A	N/A	
12	*Riviera 5*												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		665,820				6,676	4,444,976	1,000,000	4,444,976	19,128,276	2.87	4.30
15	Plant Unit Info	1,307	665,820	68.5%	93.9%	68.5%	6,676			4,444,976	19,128,276	2.87	
16	*Sanford 4*												
17	Gas		38,040				7,795	296,526	1,000,000	296,526	1,276,053	3.35	4.30
18	Plant Unit Info	1,088	38,040	4.7%	94.0%	52.2%	7,795			296,526	1,276,053	3.35	
19	*Sanford 5*												
20	Gas		134,017				7,796	1,044,785	1,000,000	1,044,785	4,496,072	3.35	4.30
21	Plant Unit Info	1,180	134,017	15.3%	94.0%	50.5%	7,796			1,044,785	4,496,072	3.35	
22	*Scherer 4*												
23	Coal		179,521					121,005	17,000,000	2,057,085	5,170,150	2.88	42.73
24	Plant Unit Info	626	179,521	38.5%	94.8%	38.5%	11,459			2,057,085	5,170,150	2.88	
25	*Space Coast*												
26	Solar		1,173					N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	10	1,173	14.1%	N/A	34.4%	N/A			N/A	N/A	N/A	
28	*St Lucie 1*												
29	Nuclear		728,079					7,699,005	1,000,000	7,699,005	3,737,096	0.51	0.49
30	Plant Unit Info	1,003	728,079	96.9%	96.9%	97.5%	10,574			7,699,005	3,737,096	0.51	
31	*St Lucie 2*												
32	Nuclear		623,343					6,459,185	1,000,000	6,459,185	3,222,487	0.52	0.50
33	Plant Unit Info	860	623,343	97.5%	97.5%	97.5%	10,362			6,459,185	3,222,487	0.52	
34	*Sunshine Gateway PV Solar*												
35	Solar		10,862					N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	10,862	19.6%	N/A	42.8%	N/A			N/A	N/A	N/A	
37	*Turkey Point 3*												
38	Nuclear		623,119					6,699,428	1,000,000	6,699,428	3,886,338	0.62	0.58
39	Plant Unit Info	859	623,119	97.5%	97.5%	97.5%	10,751			6,699,428	3,886,338	0.62	
40	*Turkey Point 4*												
41	Nuclear		615,139					6,765,447	1,000,000	6,765,447	3,381,371	0.55	0.50
42	Plant Unit Info	848	615,139	97.5%	97.5%	97.5%	10,998			6,765,447	3,381,371	0.55	
43	*Turkey Point 5*												
44	Light Oil		0					0	0	0	0	0.00	0.00
45	Gas		59,824				8,145	487,283	1,000,000	487,283	2,096,948	3.51	4.30
46	Plant Unit Info	1,227	59,824	6.6%	48.8%	65.9%	8,145			487,283	2,096,948	3.51	
47	*WCEC 01*												
48	Light Oil		0					0	0	0	0	0.00	0.00
49	Gas		547,205				6,645	3,635,950	1,000,000	3,635,950	15,563,272	2.84	4.28
50	Plant Unit Info	1,267	547,205	58.1%	73.5%	58.1%	6,645			3,635,950	15,563,272	2.84	
51	*WCEC 02*												
52	Light Oil		0					0	0	0	0	0.00	0.00
53	Gas		722,974				6,651	4,808,761	1,000,000	4,808,761	20,583,354	2.85	4.28
54	Plant Unit Info	1,267	722,974	76.7%	93.9%	76.7%	6,651			4,808,761	20,583,354	2.85	
55	*WCEC 03*												
56	Light Oil		0					0	0	0	0	0.00	0.00
57	Gas		689,352				6,736	4,643,238	1,000,000	4,643,238	19,874,854	2.88	4.28
58	Plant Unit Info	1,242	689,352	74.6%	93.9%	74.6%	6,736			4,643,238	19,874,854	2.88	
59	*Wildflower PV Solar*												
60	Solar		12,052					N/A	N/A	N/A	N/A	N/A	N/A
61	Plant Unit Info	74.5	12,052	21.7%	N/A	47.4%	N/A			N/A	N/A	N/A	
62	*System Totals*												
63	Plant Unit Info	27,092	9,094,171				7,797			70,906,949	196,648,933	2.16	
64													
65													

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	FCR - E-5 Schedule	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	**#6 Heavy Oil (BBLS)**							
2	Purchases							
3	Units	0	150,000	0	0	0	0	150,000
4	Unit Cost	0.0000	75.8533	0.0000	0.0000	0.0000	0.0000	75.8533
5	Amount	$0	$11,378,000	$0	$0	$0	$0	$11,378,000
6								
7	Burned							
8	Units	6,857	25,223	0	0	0	0	32,079
9	Unit Cost	72.9904	73.5319	0.0000	0.0000	0.0000	0.0000	73.4161
10	Amount	$500,463	$1,854,658	$0	$0	$0	$0	$2,355,121
11								
12	Ending Inventory							
13	Units	642,796	767,574	767,574	767,574	767,574	767,574	767,574
14	Unit Cost	72.9904	73.5317	73.5317	73.5317	73.5317	73.5317	73.5317
15	Amount	$46,918,000	$56,441,000	$56,441,000	$56,441,000	$56,441,000	$56,441,000	$56,441,000
16								
17	**#2 Light Oil (BBLS)**							
18	Purchases							
19	Units	20,000	0	0	0	0	0	20,000
20	Unit Cost	85.9000	0.0000	0.0000	0.0000	0.0000	0.0000	85.9000
21	Amount	$1,718,000	$0	$0	$0	$0	$0	$1,718,000
22								
23	Burned							
24	Units	0	3,495	0	0	0	0	3,495
25	Unit Cost	0.0000	89.3227	0.0000	0.0000	0.0000	0.0000	89.3227
26	Amount	$0	$312,139	$0	$0	$0	$0	$312,139
27								
28	Ending Inventory							
29	Units	1,343,899	1,340,404	1,340,404	1,340,404	1,340,404	1,340,404	1,340,404
30	Unit Cost	95.7862	95.8032	95.8032	95.8032	95.8032	95.8032	95.8032
31	Amount	$128,727,000	$128,415,000	$128,415,000	$128,415,000	$128,415,000	$128,415,000	$128,415,000
32								
33	**Coal - Scherer (MMBTU)**							
34	Purchases							
35	Units	2,132,245	2,132,245	2,132,245	2,132,245	2,132,245	2,132,245	12,793,471
36	Unit Cost	2.5044	2.5171	2.5044	2.4927	2.5058	2.5213	2.5076
37	Amount	$5,340,000	$5,367,000	$5,340,000	$5,315,000	$5,343,000	$5,376,000	$32,081,000
38								
39	Burned							
40	Units	2,273,307	2,228,356	2,063,155	2,151,018	2,020,550	2,057,085	12,793,471
41	Unit Cost	2.5335	2.5282	2.5203	2.5113	2.5095	2.5133	2.5197
42	Amount	$5,759,497	$5,633,691	$5,199,752	$5,401,930	$5,070,481	$5,170,150	$32,235,501
43								
44	Ending Inventory							
45	Units	4,417,081	4,320,970	4,390,061	4,371,288	4,482,983	4,558,143	4,558,143
46	Unit Cost	2.5336	2.5281	2.5202	2.5114	2.5095	2.5133	2.5133
47	Amount	$11,191,000	$10,924,000	$11,064,000	$10,978,000	$11,250,000	$11,456,000	$11,456,000
48								
49	**Gas (MCF)**							
50	Burned							
51	Units	62,307,670	63,037,578	56,817,986	54,197,831	43,359,891	41,226,799	320,947,755
52	Unit Cost	3.4232	3.3918	3.4373	3.5821	3.9434	4.2994	3.6292
53	Amount	$213,293,114	$213,811,626	$195,301,157	$194,142,858	$170,984,755	$177,251,491	$1,164,785,001
54								
55	**Nuclear (Other)**							
56	Burned							
57	Units	26,918,706	26,918,706	26,050,362	22,540,065	22,758,319	27,623,065	152,809,223
58	Unit Cost	0.5149	0.5149	0.5149	0.5206	0.5176	0.5151	0.5162
59	Amount	$13,860,739	$13,860,739	$13,413,618	$11,735,345	$11,780,068	$14,227,292	$78,877,801

Docket No. 20190001-EI
2019 FCR Actual Estimated
Exhibit RBD-3, Page 23 of 27

FLORIDA POWER & LIGHT COMPANY
POWER SOLD

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	SOLD TO	Type & Schedule	Total KWH Sold (000)	KWH from Own Generation (000)	Fuel Cost (cents/KWH)	Total Cost (cents/KWH)	Total $ for Fuel Adjustment (Col(5) * Col(6))	Total Cost ($) (Col(5) * Col(7))	Gain from Off System Sales ($)
1	**July Estimated**								
2	Off System	OS	114,390	114,390	2.105	3.267	$2,407,686	$3,737,280	$1,160,156
3	St Lucie Reliability Sales		51,706	51,706	0.527	0.527	$272,625	$272,625	
4	**Sub-Total July Estimated**		166,096	166,096	1.614	2.414	$2,680,311	$4,009,905	$1,160,156
5									
6	**August Estimated**								
7	Off System	OS	111,600	111,600	2.440	3.560	$2,723,552	$3,972,463	$1,072,352
8	St Lucie Reliability Sales		51,706	51,706	0.527	0.527	$272,625	$272,625	
9	**Sub-Total August Estimated**		163,306	163,306	1.835	2.599	$2,996,176	$4,245,088	$1,072,352
10									
11	**September Estimated**								
12	Off System	OS	116,550	116,550	2.089	3.350	$2,434,362	$3,904,909	$1,238,698
13	St Lucie Reliability Sales		50,038	50,038	0.527	0.527	$263,830	$263,830	
14	**Sub-Total September Estimated**		166,588	166,588	1.620	2.502	$2,698,192	$4,168,739	$1,238,698
15									
16	**October Estimated**								
17	Off System	OS	96,100	96,100	1.965	3.157	$1,888,613	$3,033,447	$885,028
18	St Lucie Reliability Sales		21,683	21,683	0.527	0.527	$114,327	$114,327	
19	**Sub-Total October Estimated**		117,783	117,783	1.701	2.673	$2,002,940	$3,147,773	$885,028
20									
21	**November Estimated**								
22	Off System	OS	195,000	195,000	1.840	2.840	$3,587,265	$5,537,628	$1,440,042
23	St Lucie Reliability Sales		23,841	23,841	0.509	0.509	$121,270	$121,270	
24	**Sub-Total November Estimated**		218,841	218,841	1.695	2.586	$3,708,535	$5,658,898	$1,440,042
25									
26	**December Estimated**								
27	Off System	OS	285,975	285,975	1.754	2.805	$5,016,808	$8,020,260	$2,226,670
28	St Lucie Reliability Sales		52,790	52,790	0.509	0.509	$268,526	$268,526	
29	**Sub-Total December Estimated**		338,765	338,765	1.560	2.447	$5,285,334	$8,288,787	$2,226,670
30									
31	**Period Total**								
32	Off System	OS	919,615	919,615	1.964	3.067	$18,058,285	$28,205,987	$8,022,945
33	St Lucie Reliability Sales		251,765	251,765	0.522	0.522	$1,313,203	$1,313,203	
34	**Sub-Total Period Total**		1,171,380	1,171,380	1.654	2.520	$19,371,488	$29,519,190	$8,022,945
35									
36									

FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER

SCHEDULE: E7

(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(5) * Col(6))
1	**July Estimated**					
2	OUC		8,660	8,660	3.198	$276,935
3	St Lucie Reliability		43,374	43,374	0.542	$235,028
4	SWA		62,496	62,496	3.414	$2,133,697
5	**Sub-Total July Estimated**		114,530	114,530	2.310	$2,645,660
6						
7	**August Estimated**					
8	OUC		7,487	7,487	3.171	$237,448
9	St Lucie Reliability		43,374	43,374	0.542	$235,028
10	SWA		66,960	66,960	3.363	$2,251,596
11	**Sub-Total August Estimated**		117,821	117,821	2.312	$2,724,071
12						
13	**September Estimated**					
14	OUC		2,280	2,280	3.149	$71,795
15	St Lucie Reliability		41,975	41,975	0.542	$227,446
16	SWA		61,200	61,200	3.347	$2,048,568
17	**Sub-Total September Estimated**		105,455	105,455	2.226	$2,347,810
18						
19	**October Estimated**					
20	OUC		2,696	2,696	3.170	$85,462
21	St Lucie Reliability		43,374	43,374	0.542	$235,028
22	SWA		63,240	63,240	3.511	$2,220,398
23	**Sub-Total October Estimated**		109,310	109,310	2.324	$2,540,888
24						
25	**November Estimated**					
26	OUC		1,527	1,527	3.255	$49,700
27	St Lucie Reliability		42,860	42,860	0.542	$232,244
28	SWA		49,680	49,680	3.900	$1,937,528
29	**Sub-Total November Estimated**		94,067	94,067	2.359	$2,219,472
30						
31	**December Estimated**					
32	OUC		720	720	3.453	$24,860
33	St Lucie Reliability		44,289	44,289	0.542	$239,986
34	SWA		55,056	55,056	3.819	$2,102,503
35	**Sub-Total December Estimated**		100,065	100,065	2.366	$2,367,349
36						
37	**Period Total**					
38	OUC		23,370	23,370	3.193	$746,200
39	St Lucie Reliability		259,245	259,245	0.542	$1,404,760
40	SWA		358,632	358,632	3.540	$12,694,290
41	**Sub-Total Period Total**		641,247	641,247	2.315	$14,845,250
42						
43						

FLORIDA POWER & LIGHT COMPANY

ENERGY PAYMENT TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1) Line No.	(2) PURCHASE FROM	(3) Type & Schedule	(4) Total KWH Purchased (000)	(5) KWH For Firm (000)	(6) Fuel Cost (cents/KWH)	(7) Total $ For Fuel Adj (Col(5) * Col(6))
1	**July Estimated**					
2	Qualifying Facilities		19,494	19,494	1.818	$354,498
3	**Sub-Total July Estimated**		19,494	19,494	1.818	$354,498
4						
5	**August Estimated**					
6	Qualifying Facilities		21,726	21,726	1.850	$401,952
7	**Sub-Total August Estimated**		21,726	21,726	1.850	$401,952
8						
9	**September Estimated**					
10	Qualifying Facilities		25,560	25,560	1.703	$435,193
11	**Sub-Total September Estimated**		25,560	25,560	1.703	$435,193
12						
13	**October Estimated**					
14	Qualifying Facilities		28,311	28,311	1.691	$478,743
15	**Sub-Total October Estimated**		28,311	28,311	1.691	$478,743
16						
17	**November Estimated**					
18	Qualifying Facilities		22,800	22,800	1.716	$391,257
19	**Sub-Total November Estimated**		22,800	22,800	1.716	$391,257
20						
21	**December Estimated**					
22	Qualifying Facilities		33,984	33,984	1.730	$587,840
23	**Sub-Total December Estimated**		33,984	33,984	1.730	$587,840
24						
25	**Period Total**					
26	Qualifying Facilities		151,875	151,875	1.745	$2,649,483
27	**Sub-Total Period Total**		151,875	151,875	1.745	$2,649,483
28						
29						

FLORIDA POWER & LIGHT COMPANY

ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JULY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	Transaction Cost (cents/KWH)	Total $ for Fuel Adj (Col(4) * Col(5))	Cost if Generated (cents/KWH)	Cost if Generated ($) (Col(4) * Col(7))	Fuel Savings ($) (Col(8) - Col(6))
1	**July Estimated**							
2	Economy	OS	49,755	2.900	$1,442,895	3.689	$1,835,285	$392,390
3	**Sub-Total July Estimated**		49,755	2.900	$1,442,895	3.689	$1,835,285	$392,390
4								
5	**August Estimated**							
6	Economy	OS	85,560	3.300	$2,823,480	4.097	$3,505,266	$681,786
7	**Sub-Total August Estimated**		85,560	3.300	$2,823,480	4.097	$3,505,266	$681,786
8								
9	**September Estimated**							
10	Economy	OS	63,600	2.300	$1,462,800	2.916	$1,854,302	$391,502
11	**Sub-Total September Estimated**		63,600	2.300	$1,462,800	2.916	$1,854,302	$391,502
12								
13	**October Estimated**							
14	Economy	OS	48,980	1.800	$881,640	2.399	$1,175,097	$293,457
15	**Sub-Total October Estimated**		48,980	1.800	$881,640	2.399	$1,175,097	$293,457
16								
17	**November Estimated**							
18	Economy	OS	7,500	1.700	$127,500	2.325	$174,396	$46,896
19	**Sub-Total November Estimated**		7,500	1.700	$127,500	2.325	$174,396	$46,896
20								
21	**December Estimated**							
22	Economy	OS	3,255	1.600	$52,080	2.131	$69,373	$17,293
23	**Sub-Total December Estimated**		3,255	1.600	$52,080	2.131	$69,373	$17,293
24								
25	**Period Total**							
26	Economy	OS	258,650	2.625	$6,790,395	3.330	$8,613,719	$1,823,324
27	**Sub-Total Period Total**		258,650	2.625	$6,790,395	3.330	$8,613,719	$1,823,324
28								
29								

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Capacity Costs	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	**Base**													
2	Payments to Non-cogenerators	$1,910,150	$1,907,896	$1,910,150	$1,910,150	$2,180,916	$2,242,910	$2,243,700	$2,243,700	$2,243,700	$2,049,600	$2,049,600	$2,049,600	$24,942,072
3	Payments to Co-generators	$113,295	$113,295	$113,295	$113,295	$113,295	$113,635	$116,165	$116,165	$116,165	$116,165	$116,165	$116,165	$1,377,100
4	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$9,683,129	$9,653,517	$9,623,904	$9,594,292	$9,564,680	$9,535,067	$9,614,389	$9,583,114	$9,551,838	$9,520,563	$9,489,287	$9,458,012	$114,871,791
5	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($88,599)	($88,211)	($87,824)	($87,436)	($87,048)	($86,660)	($87,699)	($87,289)	($86,880)	($86,470)	($86,060)	($85,651)	($1,045,826)
6	Indiantown Transaction - Regulatory Asset - Amortization and Return	$6,404,840	$6,378,202	$6,351,564	$6,324,926	$6,298,288	$6,271,649	$6,360,957	$6,332,823	$6,304,689	$6,276,555	$6,248,420	$6,220,286	$75,773,199
7	SJRPP Revenue Requirements	$986,353	$975,202	$964,052	$952,902	$941,752	$930,602	$936,673	$924,896	$913,120	$901,343	$889,567	$877,790	$11,194,253
8	Incremental Plant Security Costs O&M	$2,043,320	$1,921,966	$2,502,657	$2,137,230	$2,436,305	$2,198,128	$2,362,785	$2,076,958	$2,293,233	$2,490,140	$2,252,530	$2,486,620	$27,201,872
9	Incremental Plant Security Costs Capital	$293,456	$300,059	$300,123	$299,801	$300,311	$301,322	$314,221	$317,656	$321,045	$324,429	$328,979	$344,316	$3,745,717
10	Incremental Nuclear NRC Compliance Costs O&M	$105,951	$84,701	$62,725	$84,644	$42,971	$56,769	$222,518	$222,014	$221,510	$222,518	$221,510	$225,056	$1,772,887
11	Incremental Nuclear NRC Compliance Costs Capital	$976,433	$973,040	$991,486	$1,019,881	$1,022,865	$1,020,909	$1,059,934	$1,064,527	$1,063,146	$1,061,563	$1,059,973	$1,098,646	$12,412,404
12	Transmission of Electricity by Others	$71,812	$1,134	$38,865	$947	-	-	$21,831	$640	$27,949	$16,799	$31,375	$30,419	$241,770
13	Transmission Revenues from Capacity Sales	($1,114,638)	($941,273)	($907,773)	($683,574)	($723,347)	($368,909)	($169,438)	($176,559)	($231,848)	($259,806)	($510,321)	($776,783)	($6,864,272)
14	Total Base	$21,385,502	$21,279,528	$21,863,224	$21,667,057	$22,090,986	$22,215,424	$22,996,035	$22,618,645	$22,737,667	$22,633,398	$22,091,024	$22,044,476	$265,622,966
15														
16	**Intermediate**													
17	Incremental Plant Security Costs O&M	$99,780	$102,881	$215,547	$121,152	$35,561	$133,959	$155,696	$224,081	$180,491	$180,718	$179,968	$172,339	$1,802,171
18	Incremental Plant Security Costs Capital	$45,435	$45,338	$45,242	$45,145	$45,048	$44,952	$46,523	$46,421	$46,319	$46,217	$46,115	$46,013	$548,767
19	Total Intermediate	$145,215	$148,219	$260,788	$166,297	$80,609	$178,910	$202,219	$270,502	$226,810	$226,935	$226,082	$218,352	$2,350,938
20														
21	**Peaking**													
22	Incremental Plant Security Costs O&M	$25,297	$31,978	$27,019	$21,996	$33,783	$24,786	$42,055	$41,373	$40,691	$42,173	$45,914	$38,093	$415,158
23	Incremental Plant Security Costs Capital	$6,500	$6,482	$6,463	$6,444	$6,426	$6,407	$6,582	$6,563	$6,543	$6,523	$6,504	$6,484	$77,920
24	Total Peaking	$31,797	$38,460	$33,482	$28,440	$40,208	$31,193	$48,637	$47,935	$47,234	$48,696	$52,417	$44,577	$493,078
25														
26	**Solar**													
27	Incremental Plant Security Costs O&M	-	-	-	-	-	$156	($156)	-	-	-	-	-	$0
28	Incremental Plant Security Costs Capital	-	-	-	-	-	-	-	$2,119	$6,357	$10,594	$14,832	$23,476	$57,377
29	Total Solar						$156	($156)	$2,119	$6,357	$10,594	$14,832	$23,476	$57,377
30														
31	**General**													
32	Incremental Plant Security Costs Capital	$2,775	$2,760	$2,744	$2,729	$2,713	$2,698	$2,697	$2,681	$2,665	$2,648	$2,632	$2,616	$32,357
33	Total General	$2,775	$2,760	$2,744	$2,729	$2,713	$2,698	$2,697	$2,681	$2,665	$2,648	$2,632	$2,616	$32,357
34														
35	**Total**	$21,565,289	$21,468,967	$22,160,239	$21,864,523	$22,214,517	$22,428,381	$23,249,433	$22,941,882	$23,020,732	$22,922,272	$22,386,987	$22,333,497	$268,556,717
36														
37	Totals may not add due to rounding													

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 17
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-4

Docket No. 20190001-EI
2019 CCR Actual Estimated
Exhibit RBD-4, Page 1 of 17

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1														
2	Total Capacity Costs (Page 1, Line 35)	$21,565,289	$21,468,967	$22,160,239	$21,864,523	$22,214,517	$22,428,381	$23,249,433	$22,941,882	$23,020,732	$22,922,272	$22,386,987	$22,333,497	$268,556,717
3														
4	Total Base Capacity Costs	$21,385,502	$21,279,528	$21,863,224	$21,667,057	$22,090,986	$22,215,424	$22,996,035	$22,618,645	$22,737,667	$22,633,398	$22,091,024	$22,044,476	$265,622,966
5	Base Jurisdictional Factor [(a)]	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%
6	Total Base Jurisdictional Capacity Costs	$20,478,521	$20,377,042	$20,935,983	$20,748,136	$21,154,085	$21,273,245	$22,020,751	$21,659,366	$21,773,339	$21,673,493	$21,154,121	$21,109,548	$254,357,631
7														
8	Total Intermediate Capacity Costs	$145,215	$148,219	$260,788	$166,297	$80,609	$178,910	$202,219	$270,502	$226,810	$226,935	$226,082	$218,352	$2,350,938
9	Intermediate Jurisdictional Factor [(a)]	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%
10	Total Intermediate Jurisdictional Capacity Costs	$136,861	$139,692	$245,786	$156,730	$75,972	$168,618	$190,586	$254,941	$213,763	$213,880	$213,077	$205,791	$2,215,698
11														
12	Total Peaking Capacity Costs	$31,797	$38,460	$33,482	$28,440	$40,208	$31,193	$48,637	$47,935	$47,234	$48,696	$52,417	$44,577	$493,078
13	Peaking Jurisdictional Factor [(a)]	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%
14	Total Peaking Jurisdictional Capacity Costs	$30,317	$36,669	$31,923	$27,116	$38,336	$29,741	$46,373	$45,704	$45,035	$46,429	$49,977	$42,502	$470,122
15														
16	Total Solar Capacity Costs	-	-	-	-	-	$156	($156)	$2,119	$6,357	$10,594	$14,832	$23,476	$57,377
17	Solar Jurisdictional Factor [(a)]	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%
18	Total Solar Jurisdcitional Capacity Costs	-	-	-	-	-	$150	($149)	$2,029	$6,087	$10,145	$14,203	$22,480	$54,944
19														
20	Total Transmission Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Transmission Jurisdictional Factor [(a)]	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%
22	Total Transmission Jurisdictional Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
23														
24	Total General Capacity Costs	$2,775	$2,760	$2,744	$2,729	$2,713	$2,698	$2,697	$2,681	$2,665	$2,648	$2,632	$2,616	$32,357
25	General Jurisdictional Factor [(a)]	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%
26	Total General Jurisdictional Capacity Costs	$2,690	$2,675	$2,660	$2,645	$2,630	$2,615	$2,614	$2,598	$2,582	$2,567	$2,551	$2,535	$31,361
27														
28	Jurisdictional Capacity Costs	$20,648,389	$20,556,079	$21,216,352	$20,934,627	$21,271,024	$21,474,369	$22,260,174	$21,964,637	$22,040,806	$21,946,514	$21,433,929	$21,382,856	$257,129,755
29														
30	Nuclear Cost Recovery Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
31														
32	Net Jurisdictional Capacity Costs	$20,648,389	$20,556,079	$21,216,352	$20,934,627	$21,271,024	$21,474,369	$22,260,174	$21,964,637	$22,040,806	$21,946,514	$21,433,929	$21,382,856	$257,129,755
33														
34														
35	[(a)] As approved in Order No. PSC-2018-0610-FOF-EI.													
36														
37	Totals may not add due to rounding													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1														
2	Net Jurisdictional CCR Costs (Page 2, Line 32)	$20,648,389	$20,556,079	$21,216,352	$20,934,627	$21,271,024	$21,474,369	$22,260,174	$21,964,637	$22,040,806	$21,946,514	$21,433,929	$21,382,856	$257,129,755
3														
4	CCR Revenues (Net of Revenue Taxes)	$19,117,434	$17,986,227	$19,163,568	$19,920,133	$21,832,077	$24,399,395	$25,670,483	$25,735,220	$25,075,337	$23,441,635	$20,108,068	$19,215,359	$261,664,937
5	Prior Period True-up Provision	$350,259	$350,259	$350,259	$350,259	$350,259	$350,259	$350,259	$350,259	$350,259	$350,259	$350,259	$350,259	$4,203,102
6	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	19,467,693	18,336,486	19,513,827	20,270,391	22,182,336	24,749,654	26,020,742	26,085,478	25,425,596	23,791,894	20,458,326	19,565,618	265,868,039
7														
8	True-up Provision - Over/(Under) Recovery (Line 6 - Line 2)	($1,180,696)	($2,219,593)	($1,702,525)	($664,236)	$911,312	$3,275,285	$3,760,567	$4,120,841	$3,384,790	$1,845,380	($975,603)	($1,817,238)	$8,738,284
9	Interest Provision	$21,376	$17,248	$12,788	$9,729	$9,114	$12,345	$18,309	$25,286	$31,913	$36,354	$36,587	$33,281	$264,331
10	True-up & Interest Provision Beginning of Year - Over/(Under) Recovery	$4,203,102	$2,693,523	$140,919	($1,899,077)	($2,903,842)	($2,333,674)	$603,697	$4,032,316	$7,828,184	$10,894,629	$12,426,104	$11,136,830	$4,203,102
11	Deferred True-up - Over/(Under) Recovery	$7,161,719	$7,161,719	$7,161,719	$7,161,719	$7,161,719	$7,161,719	$7,161,719	$7,161,719	$7,161,719	$7,161,719	$7,161,719	$7,161,719	$7,161,719
12	Prior Period True-up Provision - Collected/(Refunded)	($350,259)	($350,259)	($350,259)	($350,259)	($350,259)	($350,259)	($350,259)	($350,259)	($350,259)	($350,259)	($350,259)	($350,259)	($4,203,102)
13	End of Period True-up - Over/(Under) Recovery (Lines 8 through 12)	9,855,242	7,302,639	5,262,642	4,257,877	4,828,045	7,765,417	11,194,035	14,989,904	18,056,348	19,587,823	18,298,549	16,164,334	16,164,334
14														
15	Totals may not add due to rounding													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED VARIANCES
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Line	Actual/Estimated	Original Projection	$ Difference	% Difference
1	Payments to Non-cogenerators	$24,942,072	$24,965,500	($23,428)	(0.1%)
2	Payments to Co-generators	$1,377,100	$1,393,980	($16,880)	(1.2%)
3	Cedar Bay Transaction - Reg Asset - Amort & Return	$114,871,791	$114,243,132	$628,658	0.6%
4	Cedar Bay Transaction - Reg Liability - Amort & Return	($1,045,826)	($1,037,593)	($8,234)	0.8%
5	Indiantown Transaction - Regulatory Asset - Amortization and Return	$75,773,199	$75,099,964	$673,235	0.9%
6	Incremental Plant Security Costs-Order No. PSC-02-1761 (O&M)	$29,419,202	$33,003,550	($3,584,348)	(10.9%)
7	Incremental Plant Security Costs-Order No. PSC-02-1761 (Capital)	$4,462,138	$4,657,080	($194,942)	(4.2%)
8	Incremental Nuclear NRC Compliance Costs O&M	$1,772,887	$980,901	$791,986	80.7%
9	Incremental Nuclear NRC Compliance Costs Capital	$12,412,404	$12,637,338	($224,934)	(1.8%)
10	Transmission of Electricity by Others	$241,770	$401,458	($159,689)	(39.8%)
11	Transmission Revenues from Capacity Sales	($6,864,272)	($5,444,102)	($1,420,170)	26.1%
12	SJRPP Transaction Revenue Requirements	$11,194,253	$11,100,318	$93,934	0.8%
13	Total Capacity Costs	$268,556,717	$272,001,528	($3,444,811)	(1.3%)
14					
15					
16	Totals may not add due to rounding				

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2019 CCR Actual Estimated
Exhibit RBD-4, Page 4 of 17

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED VARIANCES
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Line	Actual/Estimated	Original Projection	$ Difference	% Difference
1	Total Capacity Costs	$268,556,717	$272,001,528	($3,444,811)	(1.3%)
2					
3	Total Base Capacity Costs	$265,622,966	$268,204,165	($2,581,198)	(1.0%)
4	Base Jurisdictional Factor	95.7589%	95.7589%	$0	
5	Total Base Jurisdictionalized Capacity Costs	$254,357,631	$256,829,358	($2,471,727)	(1.0%)
6					
7	Total Intermediate Capacity Costs	$2,350,938	$3,253,346	($902,408)	(27.7%)
8	Intermediate Jurisdictional Factor	94.2474%	94.2474%	$0	
9	Total Intermediate Jurisdictionalized Capacity Costs	$2,215,698	$3,066,194	($850,496)	(27.7%)
10					
11	Total Peaking Capacity Costs	$493,078	$511,735	($18,657)	(3.6%)
12	Peaking Jurisdictional Factor	95.3443%	95.3443%	$0	
13	Total Peaking Jurisidictionalized Capacity Costs	$470,122	$487,910	($17,788)	(3.6%)
14					
15	Total Solar Capacity Costs	$57,377	$0	$57,377	N/A
16	Solar Jurisdictional Factor	95.7589%	95.7589%	$0	
17	Total Solar Jurisdictionalized Capacity Costs	$54,944	$0	$54,944	0.0%
18					
19	Total General Capacity Costs	$32,357	$32,282	$75	0.2%
20	General Jurisdictional Factor	96.9214%	96.9214%	$0	
21	Total General Jurisdictionalized Capacity Costs	$31,361	$31,288	$73	0.2%
22					
23	Total Transmission Capacity Costs	$0	$0	$0	0.0%
24	Transmission Jurisdictional Factor	89.2071%	89.2071%	$0	
25	Total Transmissioin Jurisdictionalized Costs	$0	$0	$0	0.0%
26					
27	Jurisdictional Capacity Charges	$257,129,755	$260,414,750	($3,284,995)	(1.3%)
28					
29	Nuclear Cost Recovery Costs	$0	$0	$0	0.0%
30					
31	Net Jurisdictional Capacity Costs	$257,129,755	$260,414,750	($3,284,995)	(1.3%)
32					
33	CCR Revenues	$261,664,937	$256,211,648	$5,453,289	2.1%
34	Prior Period True-up Provision	$4,203,102	$4,203,102	$0	0.0%
35	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$265,868,039	$260,414,750	$5,453,289	2.1%
36					
37	True-up Provision for Month - Over/(Under) Recovery	$8,738,284	$0	$8,738,284	N/A
38	Interest Provision for the Month	$264,331	$0	$264,331	N/A
39	True-Up & Interest Provision - Beginning of Year	$4,203,102	$4,203,102	$0	0.0%
40	Deferred True-up - Over/(Under) Recovery	$7,161,719	$0	$7,161,719	N/A
41	Prior Period True-up Provision - Collected/(Refunded) this Month	($4,203,102)	($4,203,102)	($0)	0.0%
42	End of Period True-up - Over/(Under) Recovery	$16,164,334	$0	$16,164,334	N/A
43					
44	Totals may not add due to rounding				

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - BASE
Return on Capital Investments, Depreciation and Taxes
FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	**Base**	**INVESTMENTS**														
2		Expenditures/Additions		($3,020,673)	$106,482	$37,709	$60,242	$292,563	$220,657	$505,171	$721,821	$491,343	$720,231	$837,774	($6,306,344)	($5,333,023)
3		Clearings to Plant		$3,619,867	$56,126	$530	$3,735	$3,267	$547	-	-	-	-	-	$7,334,529	$11,018,599
4		Retirements								-	-	-	-	-	-	-
5		Other		($5,355)	($1,072)	($350)	($608)	($2,686)	($2,215)	-	-	-	-	-	-	($12,287)
6																
7		Plant-In-Service/Depreciation Base	$19,225,071	$22,844,938	$22,901,064	$22,901,593	$22,905,329	$22,908,595	$22,909,142	$22,909,142	$22,909,142	$22,909,142	$22,909,142	$22,909,142	$30,243,670	$301,385,112
8		Less: Accumulated Depreciation	$1,671,272	$1,764,013	$1,865,831	$1,968,448	$2,070,811	$2,171,105	$2,271,876	$2,374,863	$2,477,849	$2,580,836	$2,683,822	$2,786,809	$2,899,580	$29,587,115
9		CWIP - Non Interest Bearing	$12,852,631	$9,831,957	$9,938,439	$9,976,148	$10,036,391	$10,328,954	$10,549,611	$11,054,782	$11,776,604	$12,267,947	$12,988,178	$13,825,952	$7,519,608	$142,947,202
10																
11		Net Investment (Lines 7 - 8 + 9)	$30,406,430	$30,912,883	$30,973,672	$30,909,294	$30,870,909	$31,066,444	$31,186,877	$31,589,062	$32,207,896	$32,596,253	$33,213,497	$33,948,285	$34,863,699	$414,745,199
12																
13		Average Net Investment		$30,659,656	$30,943,277	$30,941,483	$30,890,101	$30,968,676	$31,126,660	$31,387,969	$31,898,479	$32,402,075	$32,904,875	$33,580,891	$34,405,992	$382,110,134
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes [(a)]		$161,387	$162,880	$162,870	$162,600	$163,013	$163,845	$175,904	$178,765	$181,587	$184,405	$188,193	$192,817	$2,078,266
17		b. Debt Component (Line 13 x debt rate x 1/12) [(b)]		$33,974	$34,288	$34,286	$34,229	$34,316	$34,491	$35,330	$35,905	$36,472	$37,038	$37,799	$38,727	$426,856
18																
19		Investment Expenses														
20		a. Depreciation		$98,095	$102,891	$102,966	$102,972	$102,981	$102,986	$102,987	$102,987	$102,987	$102,987	$102,987	$112,771	$1,240,595
21		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Total System Recoverable Expenses (Lines 16 + 17 + 20)		$293,456	$300,059	$300,123	$299,801	$300,311	$301,322	$314,221	$317,656	$321,045	$324,429	$328,979	$344,316	$3,745,717
25																
26																
27																
28																

29 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report
30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.
31 [(b)] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earnings Surveillance Report.
32
33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - INTERMEDIATE
Return on Capital Investments, Depreciation and Taxes
FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	**Intermediate**	**INVESTMENTS**														
2		Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
3		Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
4		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$69,432,794
8		Less: Accumulated Depreciation	$582,118	$597,278	$612,438	$627,598	$642,758	$657,918	$673,078	$688,238	$703,398	$718,558	$733,718	$748,878	$764,038	$8,750,015
9		CWIP - Non Interest Bearing														
10																
11		Net Investment (Lines 7 - 8 + 9)	$4,758,866	$4,743,706	$4,728,546	$4,713,386	$4,698,226	$4,683,066	$4,667,906	$4,652,746	$4,637,586	$4,622,426	$4,607,266	$4,592,106	$4,576,946	$60,682,779
12																
13		Average Net Investment		$4,751,286	$4,736,126	$4,720,966	$4,705,806	$4,690,646	$4,675,486	$4,660,326	$4,645,166	$4,630,006	$4,614,846	$4,599,686	$4,584,526	$56,014,873
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes [a]		$25,010	$24,930	$24,850	$24,770	$24,691	$24,611	$26,117	$26,032	$25,947	$25,862	$25,777	$25,693	$304,292
17		b. Debt Component (Line 13 x debt rate x 1/12) [b]		$5,265	$5,248	$5,231	$5,215	$5,198	$5,181	$5,246	$5,229	$5,212	$5,194	$5,177	$5,160	$62,555
18																
19		Investment Expenses														
20		a. Depreciation		$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$181,919
21		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Total System Recoverable Expenses (Lines 16 + 17 + 20)		$45,435	$45,338	$45,242	$45,145	$45,048	$44,952	$46,523	$46,421	$46,319	$46,217	$46,115	$46,013	$548,767
25																
26																
27																
28																

29 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report
30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.
31 [b] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earnings Surveillance Report.
32
33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - PEAKING
Return on Capital Investments, Depreciation and Taxes
FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	**Peaking**	**INVESTMENTS**														
2		Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
3		Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
4		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		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	$8,746,179
8		Less: Accumulated Depreciation	$110,891	$113,820	$116,749	$119,678	$122,607	$125,537	$128,466	$131,395	$134,324	$137,253	$140,182	$143,112	$146,041	$1,670,055
9		CWIP - Non Interest Bearing														
10																
11		Net Investment (Lines 7 - 8 + 9)	$561,892	$558,963	$556,034	$553,105	$550,176	$547,246	$544,317	$541,388	$538,459	$535,530	$532,600	$529,671	$526,742	$7,076,124
12																
13		Average Net Investment		$560,428	$557,499	$554,569	$551,640	$548,711	$545,782	$542,853	$539,923	$536,994	$534,065	$531,136	$528,207	$6,531,807
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes [a]		$2,950	$2,935	$2,919	$2,904	$2,888	$2,873	$3,042	$3,026	$3,009	$2,993	$2,977	$2,960	$35,476
17		b. Debt Component (Line 13 x debt rate x 1/12) [b]		$621	$618	$615	$611	$608	$605	$611	$608	$604	$601	$598	$595	$7,294
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 Expenses (Lines 16 + 17 + 20)		$6,500	$6,482	$6,463	$6,444	$6,426	$6,407	$6,582	$6,563	$6,543	$6,523	$6,504	$6,484	$77,920
25																
26																
27																
28																

29 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report

30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [b] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - GENERAL
Return on Capital Investments, Depreciation and Taxes
FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	**General**	**INVESTMENTS**														
2		Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
3		Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
4		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$1,888,689
8		Less: Accumulated Depreciation	$88,575	$90,996	$93,418	$95,839	$98,261	$100,682	$103,103	$105,525	$107,946	$110,368	$112,789	$115,210	$117,632	$1,340,343
9		CWIP - Non Interest Bearing														
10																
11		Net Investment (Lines 7 - 8 + 9)	$56,709	$54,287	$51,866	$49,445	$47,023	$44,602	$42,180	$39,759	$37,338	$34,916	$32,495	$30,073	$27,652	$548,345
12																
13		Average Net Investment		$55,498	$53,077	$50,655	$48,234	$45,813	$43,391	$40,970	$38,548	$36,127	$33,706	$31,284	$28,863	$506,165
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes [(a)]		$292	$279	$267	$254	$241	$228	$230	$216	$202	$189	$175	$162	$2,736
17		b. Debt Component (Line 13 x debt rate x 1/12) [(b)]		$61	$59	$56	$53	$51	$48	$46	$43	$41	$38	$35	$32	$565
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	$2,421	$29,057
21		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Total System Recoverable Expenses (Lines 16 + 17 + 20)		$2,775	$2,760	$2,744	$2,729	$2,713	$2,698	$2,697	$2,681	$2,665	$2,648	$2,632	$2,616	$32,357
25																
26																
27																
28																

29 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report
30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.
31 [(b)] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earnings Surveillance Report.
32
33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - SOLAR
Return on Capital Investments, Depreciation and Taxes
FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	**Solar**	**INVESTMENTS**														
2		Expenditures/Additions		-	-	-	-	-	-	-	$629,691	$629,691	$629,691	$629,691	($2,518,764)	-
3		Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	$3,148,455	$3,148,455
4		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	-	-	-	-	-	-	-	-	-	-	-	-	$3,148,455	
8		Less: Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	$4,421	
9		CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	$629,691	$1,259,382	$1,889,073	$2,518,764	-	
10																
11		Net Investment (Lines 7 - 8 + 9)	-	-	-	-	-	-	-	-	$629,691	$1,259,382	$1,889,073	$2,518,764	$3,144,034	
12																
13		Average Net Investment		-	-	-	-	-	-	-	$314,846	$944,537	$1,574,228	$2,203,919	$2,831,399	
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes [(a)]		-	-	-	-	-	-	-	$1,764	$5,293	$8,822	$12,351	$15,868	$44,099
17		b. Debt Component (Line 13 x debt rate x 1/12) [(b)]		-	-	-	-	-	-	-	$354	$1,063	$1,772	$2,481	$3,187	$8,857
18																
19		Investment Expenses														
20		a. Depreciation		-	-	-	-	-	-	-	-	-	-	-	$4,421	$4,421
21		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Total System Recoverable Expenses (Lines 16 + 17 + 20)		-	-	-	-	-	-	-	$2,119	$6,357	$10,594	$14,832	$23,476	$57,377
25																
26																
27																
28																

29 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report
30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.
31 [(b)] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earnings Surveillance Report.
32
33 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 2019 THROUGH DECEMBER 2019

Line No.	Line	Beginning of Period Amount	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	**INVESTMENTS**														
2	Expenditures/Additions		$92,683	$196,199	$2,463,781	($556,901)	$55,847	$99,581	($2,183,407)	$211,646	$201,695	$151,797	$199,521	($1,297,542)	($365,100)
3	Clearings to Plant		$1,570,535	($979,055)	$3,287,530	$1,293,655	$16,114	$5,322	$2,716,289	-	-	-	-	$8,923,203	$16,833,593
4	Retirements		$1,493,291	-	-	-	-	-	-	-	-	-	-	-	$1,493,291
5	Other														
6															
7	Plant-In-Service/Depreciation Base	$99,652,310	$101,222,845	$100,243,790	$103,531,320	$104,824,975	$104,841,089	$104,846,411	$107,562,700	$107,562,700	$107,562,700	$107,562,700	$107,562,700	$116,485,903	
8	Less: Accumulated Depreciation	$7,412,434	$9,288,635	$9,672,549	$10,061,541	$10,460,769	$10,862,957	$11,265,189	$11,672,276	$12,084,208	$12,496,139	$12,908,070	$13,320,001	$13,747,098	
9	CWIP - Non Interest Bearing	$1,013,321	$1,106,004	$1,302,203	$3,765,984	$3,209,082	$3,264,929	$3,364,510	$1,181,103	$1,392,749	$1,594,444	$1,746,242	$1,945,763	$648,221	
10															
11	Net Investment (Lines 7 - 8 + 9)	$93,253,198	$93,040,214	$91,873,444	$97,235,763	$97,573,289	$97,243,061	$96,945,732	$97,071,527	$96,871,242	$96,661,006	$96,400,872	$96,188,462	$103,387,026	
12															
13	Average Net Investment		$93,146,706	$92,456,829	$94,554,604	$97,404,526	$97,408,175	$97,094,397	$97,008,630	$96,971,384	$96,766,124	$96,530,939	$96,294,667	$99,787,744	
14															
15	Return on Average Net Investment														
16	a. Equity Component grossed up for taxes [(a)]		$490,307	$486,676	$497,718	$512,719	$512,738	$511,087	$543,654	$543,445	$542,295	$540,977	$539,653	$559,228	$6,280,496
17	b. Debt Component (Line 13 x debt rate x 1/12) [(b)]		$103,216	$102,451	$104,776	$107,934	$107,938	$107,590	$109,193	$109,151	$108,920	$108,655	$108,389	$112,321	$1,290,535
18															
19	Investment Expenses														
20	a. Depreciation		$382,910	$383,914	$388,992	$399,228	$402,188	$402,232	$407,087	$411,931	$411,931	$411,931	$411,931	$427,097	$4,841,373
21	b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	
22	c. Other		-	-	-	-	-	-	-	-	-	-	-	-	
23															
24	Total System Recoverable Expenses (Lines 16 + 17 + 20)		$976,433	$973,040	$991,486	$1,019,881	$1,022,865	$1,020,909	$1,059,934	$1,064,527	$1,063,146	$1,061,563	$1,059,973	$1,098,646	$12,412,404
25															
26															
27															
28															

29 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report

30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [(b)] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 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 2019 THROUGH DECEMBER 2019

Line No.	Line	Beginning of Period	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1															
2	Regulatory Asset - Loss of PPA		$334,607,181	$329,959,859	$325,312,537	$320,665,215	$316,017,893	$311,370,571	$306,723,249	$302,075,927	$297,428,605	$292,781,283	$288,133,961	$283,486,639	
3															
4	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
5															
6	Unamortized Regulatory Asset - Loss of PPA	$334,607,181	$329,959,859	$325,312,537	$320,665,215	$316,017,893	$311,370,571	$306,723,249	$302,075,927	$297,428,605	$292,781,283	$288,133,961	$283,486,639	$278,839,317	
7															
8	Average Unamortized Regulatory Asset - Loss of PPA		$332,283,520	$327,636,198	$322,988,876	$318,341,554	$313,694,232	$309,046,910	$304,399,588	$299,752,266	$295,104,944	$290,457,622	$285,810,300	$281,162,978	
9															
10	Regulatory Asset - Income Tax Gross Up	210,133,801	210,133,801	207,215,276	204,296,751	201,378,226	198,459,701	195,541,176	192,622,651	189,704,126	186,785,601	183,867,076	180,948,551	178,030,026	
11															
12	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
13															
14	Unamortized Regulatory Asset - Income Tax Gross Up		207,215,276	204,296,751	201,378,226	198,459,701	195,541,176	192,622,651	189,704,126	186,785,601	183,867,076	180,948,551	178,030,026	175,111,501	
15															
16	Return on Unamortized Regulatory Asset - Loss of PPA only														
17	Equity Component [a]		$1,305,775	$1,287,512	$1,269,249	$1,250,987	$1,232,724	$1,214,462	$1,273,547	$1,254,104	$1,234,660	$1,215,217	$1,195,773	$1,176,330	$14,910,339
18															
19	Equity Comp. grossed up for taxes [a][b]		$1,749,078	$1,724,616	$1,700,153	$1,675,691	$1,651,228	$1,626,765	$1,705,910	$1,679,865	$1,653,821	$1,627,777	$1,601,732	$1,575,688	$19,972,324
20															
21	Debt Component (Line 8 * debt rate / 12) [b]		$368,203	$363,054	$357,904	$352,754	$347,605	$342,455	$342,632	$337,401	$332,170	$326,939	$321,708	$316,477	$4,109,302
22															
23	Total Return Requirements (Line 19 + 21)		$2,117,282	$2,087,670	$2,058,057	$2,028,445	$1,998,833	$1,969,220	$2,048,542	$2,017,267	$1,985,991	$1,954,716	$1,923,440	$1,892,165	$24,081,627
24	Total Recoverable Costs (Line 4 + 12 + 23)		$9,683,129	$9,653,517	$9,623,904	$9,594,292	$9,564,680	$9,535,067	$9,614,389	$9,583,114	$9,551,838	$9,520,563	$9,489,287	$9,458,012	$114,871,791
25															
26															

27 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report

28 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

29 □

30 [b] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

31

32 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 2019 THROUGH DECEMBER 2019

Line No.	Line	Beginning of Period Amount	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1															
2	Regulatory Liability - Book/Tax Timing Difference [c]		($4,382,533)	($4,321,665)	($4,260,797)	($4,199,929)	($4,139,061)	($4,078,193)	($4,017,325)	($3,956,457)	($3,895,589)	($3,834,721)	($3,773,853)	($3,712,985)	
3															
4	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
5															
6	Unamortized Regulatory Liability - Book/Tax Timing Diff	($4,382,533)	($4,321,665)	($4,260,797)	($4,199,929)	($4,139,061)	($4,078,193)	($4,017,325)	($3,956,457)	($3,895,589)	($3,834,721)	($3,773,853)	($3,712,985)	($3,652,117)	
7															
8	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		($4,352,099)	($4,291,231)	($4,230,363)	($4,169,495)	($4,108,627)	($4,047,759)	($3,986,891)	($3,926,023)	($3,865,155)	($3,804,287)	($3,743,419)	($3,682,551)	
9															
10	Return on Unamortized Regulatory Liability - Book/Tax Timing Difference														
11	Equity Component [a]		($17,102)	($16,863)	($16,624)	($16,385)	($16,146)	($15,906)	($16,680)	($16,426)	($16,171)	($15,916)	($15,662)	($15,407)	($195,289)
12															
13	Equity Comp. grossed up for taxes [a]		($22,909)	($22,588)	($22,268)	($21,947)	($21,627)	($21,307)	($22,343)	($22,002)	($21,661)	($21,320)	($20,979)	($20,638)	($261,589)
14															
15	Debt Component (Line 8 * debt rate / 12) [b]		($4,823)	($4,755)	($4,688)	($4,620)	($4,553)	($4,485)	($4,488)	($4,419)	($4,351)	($4,282)	($4,214)	($4,145)	($53,822)
16															
17	Total Return Requirements (Line 13 + 15)		($27,731)	($27,343)	($26,956)	($26,568)	($26,180)	($25,792)	($26,831)	($26,421)	($26,012)	($25,602)	($25,192)	($24,783)	($315,410)
18	Total Recoverable Costs (Line 4 + 13 + 15)		($88,599)	($88,211)	($87,824)	($87,436)	($87,048)	($86,660)	($87,699)	($87,289)	($86,880)	($86,470)	($86,060)	($85,651)	($1,045,826)
19															

20 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report
21 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.
22 [b] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earnings Surveillance Report.
23 [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.
24
25 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 2019 THROUGH DECEMBER 2019

Line No.	Line	Beginning of Period	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1															
2	Regulatory Asset - Loss of PPA [c]		$351,166,666	$346,986,110	$342,805,555	$338,624,999	$334,444,444	$330,263,888	$326,083,333	$321,902,777	$317,722,222	$313,541,666	$309,361,110	$305,180,555	
3															
4	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
5															
6	Unamortized Regulatory Asset - Loss of PPA	$351,166,666	$346,986,110	$342,805,555	$338,624,999	$334,444,444	$330,263,888	$326,083,333	$321,902,777	$317,722,222	$313,541,666	$309,361,110	$305,180,555	$300,999,999	
7															
8	Average Unamortized Regulatory Asset - Loss of PPA		$349,076,388	$344,895,833	$340,715,277	$336,534,722	$332,354,166	$328,173,610	$323,993,055	$319,812,499	$315,631,944	$311,451,388	$307,270,833	$303,090,277	
9															
10	Return on Unamortized Regulatory Asset - Loss of PPA only														
11	Equity Component [a]		$1,371,765	$1,355,337	$1,338,909	$1,322,480	$1,306,052	$1,289,624	$1,355,522	$1,338,032	$1,320,541	$1,303,050	$1,285,560	$1,268,069	$15,854,942
12															
13	Equity Comp. grossed up for taxes [a]		$1,837,473	$1,815,467	$1,793,462	$1,771,456	$1,749,450	$1,727,445	$1,815,715	$1,792,287	$1,768,858	$1,745,429	$1,722,001	$1,698,572	$21,237,615
14															
15	Debt Component (Line 8 * debt rate / 12) [b]		$386,812	$382,179	$377,547	$372,914	$368,282	$363,649	$364,687	$359,981	$355,275	$350,570	$345,864	$341,158	$4,368,917
16															
17	Total Return Requirements (Line 13 + 15)		$2,224,285	$2,197,646	$2,171,008	$2,144,370	$2,117,732	$2,091,094	$2,180,402	$2,152,268	$2,124,133	$2,095,999	$2,067,865	$2,039,731	$25,606,532
18	Total Recoverable Costs (Line 4 + 17)		$6,404,840	$6,378,202	$6,351,564	$6,324,926	$6,298,288	$6,271,649	$6,360,957	$6,332,823	$6,304,689	$6,276,555	$6,248,420	$6,220,286	$75,773,199
19															
20															

21 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report
22 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.
23 [b] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507%
24 based on the May 2019 Earnings Surveillance Report.
25 [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.
26
27 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 2019 THROUGH DECEMBER 2019

Line No.	Line	Beginning Balance	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1	Regulatory Asset - SJRPP Transaction Shutdown Payment [c]		$66,817,392	$64,852,175	$62,886,957	$60,921,740	$58,956,522	$56,991,305	$55,026,088	$53,060,870	$51,095,653	$49,130,435	$47,165,218	$45,200,000	
2	Regulatory Asset - SJRPP Transaction Shutdown Payment Amortization		$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$23,582,609
3	Unamortized Regulatory Asset - SJRPP Transaction Shutdown Payment	$66,817,392	$64,852,175	$62,886,957	$60,921,740	$58,956,522	$56,991,305	$55,026,088	$53,060,870	$51,095,653	$49,130,435	$47,165,218	$45,200,000	$43,234,783	
4															
5	Other regulatory liability - SJRPP Suspension Liability		($7,320,787)	($7,105,470)	($6,890,152)	($6,674,835)	($6,459,518)	($6,244,201)	($6,028,883)	($5,813,566)	($5,598,249)	($5,382,932)	($5,167,614)	($4,952,297)	
6	Other regulatory liability - SJRPP Suspension Liability Amortization (Refund)		($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($2,583,807)
7	Unamortized Regulatory Liability - SJRPP Suspension Liability	($7,320,787)	($7,105,470)	($6,890,152)	($6,674,835)	($6,459,518)	($6,244,201)	($6,028,883)	($5,813,566)	($5,598,249)	($5,382,932)	($5,167,614)	($4,952,297)	($4,736,980)	
8															
9	Average Net Unamortized Regulatory Asset/Liab (Lines 3 + 7)		$58,621,655	$56,871,755	$55,121,855	$53,371,954	$51,622,054	$49,872,154	$48,122,254	$46,372,354	$44,622,454	$42,872,554	$41,122,653	$39,372,753	
10															
11	Equity Component		$230,366	$223,489	$216,612	$209,736	$202,859	$195,983	$201,334	$194,013	$186,691	$179,370	$172,049	$164,728	$2,377,229
12	Equity Comp. grossed up for taxes		$308,573	$299,362	$290,151	$280,940	$271,729	$262,518	$269,686	$259,879	$250,072	$240,265	$230,459	$220,652	$3,184,287
13	Debt Component (Line 9 x debt rate x 1/12)		$64,959	$63,020	$61,081	$59,141	$57,202	$55,263	$54,166	$52,197	$50,227	$48,257	$46,288	$44,318	$656,119
14															
15	Total Return Requirements (Line 12 + 13)		$373,532	$362,382	$351,232	$340,081	$328,931	$317,781	$323,852	$312,076	$300,299	$288,523	$276,746	$264,970	$3,840,406
16															
17	Other SJRPP Transaction Items [d]														
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 + 12 + 13 + 18 + 19)		$986,353	$975,202	$964,052	$952,902	$941,752	$930,602	$936,673	$924,896	$913,120	$901,343	$889,567	$877,790	$11,194,252
22															
23															
24															

25 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 ROR Surveillance Report
26 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.
27 [b] The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earnings Surveillance Report.
28 [c] Recovery of the SJRPP Transaction over a 46 month period is based on the settlement agreement approved by the FPSC in Docket No. 20170123-EI Order No. PSC-2017-0415-AS-EI.
29 [d] The total amount of SJRPP Deferred Interest and Article 8 PPA Dismantlement Accrual to refund is $12.4M and $39.9M, respectively. The unamortized balances for these regulatory liabilities are a reflected in rate base.
30
31 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2018 EARNINGS SURVEILLANCE REPORT

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

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

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

DEBT COMPONENTS:	
LONG TERM DEBT	1.2073%
SHORT TERM DEBT	0.0900%
CUSTOMER DEPOSITS	0.0246%
TAX CREDITS -WEIGHTED	0.0078%
TOTAL DEBT	**1.3297%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.6852%
TAX CREDITS -WEIGHTED	0.0303%
TOTAL EQUITY	**4.7156%**
TOTAL	6.0452%
PRE-TAX EQUITY	6.3165%
PRE-TAX TOTAL	7.6461%

Note:

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

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
CALCULATION OF TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

SCHEDULE: E1-A

E1-A True-Up Summary	Total
1. End of Period True-Up [1]	($158,761,654)
2. Less: Actual Estimated True-up for the same period [2]	($88,108,249)
3. Net True-up for the period	($70,653,405)

[1] Page 2, Column 15, Lines 40 & 41

[2] Approved in FPSC Final Order PSC-2018-0610-FOF-EI

Note: Totals may not add due to rounding.

( ) Reflects Underrecovery

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 18
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-5

REVISED 7/26/19

Docket No. 20190001-EI
2018 FCR Final True Up
Exhibit RBD-5, Page 1 of 3

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

SCHEDULE: E1-B

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	True-up	True Up Line	a-Jan - 2018	a-Feb - 2018	a-Mar - 2018	a-Apr - 2018	a-May - 2018	a-Jun - 2018	a-Jul - 2018	a-Aug - 2018	a-Sep - 2018	a-Oct - 2018	a-Nov - 2018	a-Dec - 2018	a-2018
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	$243,085,192	$233,591,015	$214,637,822	$232,227,371	$249,785,380	$278,196,301	$296,181,995	$302,312,660	$313,118,581	$307,140,535	$269,491,495	$294,578,787	$3,234,347,133
2		SJRPP Fuel Inventory Expense	$4,996,469												$4,996,469
3		Scherer Coal Cars Depreciation & Return			($2,311)	($52,651)									($54,962)
4		Cedar Bay – Rail Coal Cars Lease	$649,217	$402,076	($182,761)	$463,585	$234,001	$1,034,482	$1,914,506	($66,155)	$797,743	$286,914	$519,804	$690,876	$6,744,289
5		Fuel Cost of Stratified Sales	($826,924)	($2,635,194)	($1,242,878)	($2,454,710)	($896,866)	($2,451,517)	($3,316,610)	($3,092,829)	($2,998,708)	($3,219,174)	($3,081,166)	($2,370,828)	($28,587,406)
6		Fuel Cost of Power Sold (Per A6)	($11,254,619)	($6,322,850)	($6,543,614)	($2,113,385)	($5,410,548)	($2,909,968)	($3,050,183)	($2,924,894)	($1,970,471)	($2,613,083)	($6,344,058)	($8,473,622)	($59,931,294)
7		Gains from Off-System Sales (Per A6)	($12,786,865)	($2,885,156)	($2,843,784)	($806,000)	($2,408,061)	($1,211,737)	($1,326,065)	($634,240)	($1,230,189)	($1,107,285)	($1,645,142)	($2,446,754)	($31,331,278)
8		Fuel Cost of Purchased Power (Per A7)	$3,007,258	$1,463,004	$2,541,679	$2,565,137	$1,240,528	$4,359,681	$1,535,914	$3,072,905	$3,179,060	$1,782,418	$3,759,500	$2,418,183	$30,925,266
9		Energy Payments to Qualifying Facilities (Per A8)	$443,260	$350,206	$284,154	$216,279	$316,743	$474,881	$317,094	$386,056	$546,027	$819,311	$711,947	$603,375	$5,469,331
10		Energy Cost of Economy Purchases (Per A9)	$14,131	$12,615	$8,391	$892,096	$116,832	$1,833,085	$491,910	$1,370,715	$2,542,261	$3,179,247	$55,507	$129,606	$10,646,395
11		Total Fuel Costs & Net Power Transactions	227,327,118	223,975,715	206,656,698	230,937,722	242,978,008	279,325,207	292,748,561	300,424,218	313,984,305	306,268,881	263,467,886	285,129,624	3,173,223,943
12															
13	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$42,272	$37,555	$42,032	$44,237	$49,641	$44,511	$42,505	$44,173	$39,617	$45,255	$43,306	$41,345	$516,451
14		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$264,122	$190,332	$227,335	$62,122	$165,868	$71,172	$69,326	$53,599	$53,191	$61,857	$169,175	$223,022	$1,611,119
15		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($224)	($632)	($140)	($14,803)	($1,565)	($27,905)	($7,095)	($18,615)	($37,304)	($39,380)	($976)	($2,575)	($151,215)
16		Total Incremental Optimization Costs	306,170	227,255	269,228	91,555	213,943	87,778	104,736	79,157	55,504	67,732	211,505	261,791	1,976,355
17															
18	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($40,028)	($104,158)	($31,590)	($38,401)	($67,894)	($107,952)	($147,312)	($79,676)	($107,584)	($170,067)	($166,283)	($89,787)	($1,150,732)
19		Inventory Adjustments	$120,176	$130,505	$3,814	$41,771	$1,035,106	($701,824)	($319,763)	$449,050	$276,930	$30,926	$54,104	($64,411)	$1,056,384
20		Non Recoverable Oil/Tank Bottoms						$222,715							$222,715
21		Other O&M Expense		$1,530				$199,751		$349,662	$20,428	($0)			$571,371
22		Adjusted Total Fuel Costs & Net Power Transactions	227,713,437	224,230,846	206,898,150	231,032,646	244,159,164	279,025,675	292,386,222	301,222,410	314,229,583	306,197,473	263,567,213	285,237,217	3,175,900,036
23															
24	**kWh Sales**	Jurisdictional kWh Sales	8,262,961,939	7,655,562,391	7,658,691,776	8,020,344,013	8,908,457,763	9,630,385,468	10,669,863,413	11,037,589,280	10,444,184,942	10,554,149,683	9,185,318,934	8,025,631,481	110,053,141,083
25		Sales for Resale (excluding Stratified Sales)	401,044,771	440,593,709	406,083,666	407,540,643	449,608,712	461,042,727	544,159,311	580,072,443	556,073,813	544,201,229	514,143,681	426,135,345	5,730,700,050
26		Sub-Total Sales	8,664,006,710	8,096,156,100	8,064,775,442	8,427,884,656	9,358,066,475	10,091,428,195	11,214,022,724	11,617,661,723	11,000,258,755	11,098,350,912	9,699,462,615	8,451,766,826	115,783,841,133
27															
28		**Jurisdictional % of Total Sales (Line 24/26)**	95.37114%	94.55799%	94.96472%	95.16438%	95.19550%	95.43134%	95.14751%	95.00698%	94.94490%	95.09656%	94.69926%	94.95803%	95.05052%
29															
30	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$215,083,204	$198,105,794	$194,179,392	$204,602,796	$229,930,394	$250,662,270	$281,327,173	$292,069,109	$276,639,549	$279,679,927	$239,212,570	$206,106,538	$2,867,598,717
31															
32	**Fuel Adjustment Revenues Not Applicable to Period**														
33		Prior Period True-Up (Collected)/Refunded This Period [2]	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$16,792,378
34		GPIF, Net of Revenue Taxes [3]	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($9,649,084)
35		Incentive Mechanism, Net of Revenue Taxes [5]	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($9,526,193)
36		Jurisdictional Fuel Revenues Applicable to Period	214,884,629	197,907,219	193,980,817	204,404,221	229,731,820	250,463,695	281,128,598	291,870,534	276,440,974	279,481,352	239,013,995	205,907,963	2,865,215,818
37		Adjusted Total Fuel Costs & Net Power Transactions	227,713,437	224,230,846	206,898,150	231,032,646	244,159,164	279,025,675	292,386,222	301,222,410	314,229,583	306,197,473	263,567,213	285,237,217	3,175,900,036
38		Jurisdictional Sales % of Total kWh Sales (Line 28)	95.37114%	94.55799%	94.96472%	95.16438%	95.19550%	95.43134%	95.14751%	95.00698%	94.94490%	95.09656%	94.69926%	94.95803%	95.05052%
39		Juris. Total Fuel Costs & Net Power Trans. (Line 37xLine38x1.00133)	217,461,740	212,310,178	196,741,567	220,153,200	232,737,667	266,632,090	278,568,213	286,562,937	298,741,763	291,570,537	249,928,163	271,215,880	3,022,623,937
40		True-Up Provision for the Month-Over/(Under) Recovery (Line 36- Line 39)	($2,577,111)	($14,402,959)	($2,760,750)	($15,748,980)	($3,005,847)	($16,168,395)	$2,560,385	$5,307,597	($22,300,788)	($12,089,185)	($10,914,168)	($65,307,917)	($157,408,119)
41		Interest Provision for the Month	($11,182)	($24,035)	($41,664)	($60,952)	($77,705)	($98,131)	($114,895)	($110,902)	($134,814)	($179,106)	($207,611)	($292,537)	($1,353,535)
42		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	$16,792,378	$12,804,720	($3,021,640)	($7,223,419)	($24,432,716)	($28,915,633)	($46,581,523)	($45,535,398)	($41,738,069)	($65,573,036)	($79,240,691)	($91,761,835)	$16,792,378
43		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)
44		Prior Period True-Up Collected/(Refunded) This Period	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($16,792,378)
45		End of Period Net True-up Amount Over/(Under) Recovery (Line 40 - 44)	($10,827,547)	($26,653,907)	($30,855,686)	($48,064,983)	($52,547,900)	($70,213,790)	($69,167,665)	($65,370,336)	($89,205,303)	($102,872,958)	($115,394,102)	($182,393,921)	($182,393,921)
46															
47															

48 [1] Actuals include various adjustments as noted on the A-Schedules.

49 [2] Prior Period 2017 Actual/Estimated True-up.

50 [3] Generating Performance Incentive Factor is (($9,656,036/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI.

51 [4] Other Fuel Expense consists of nuclear fuel design software maintenance costs.

52 [5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($9,533,057/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI

53 [6] 2017 Final True-up.

54

55 Note: Totals may not add due to rounding.

56

57 ( ) Reflects Underrecovery

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Docket No. 20190001-EI
2018 FCR Final True Up
Exhibit RBD-5, Page 2 of 3

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	True-up	True Up Line	2018			
			FCR - Final True-up	FCR - Actual/Estimated	$ Dif. FCR - Actual/Estimated	% Dif. FCR - Actual/Estimated
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	$3,234,347,133	$3,049,738,951	$184,608,182	6.05%
2		SJRPP Fuel Inventory Expense	$4,996,469	$4,996,469	$0	0.00%
3		Scherer Coal Cars Depreciation & Return	($54,962)	($54,962)	$0	0.00%
4		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$6,744,289	$6,035,632	$708,657	11.74%
5		Fuel Cost of Stratified Sales	($28,587,406)	($26,276,574)	($2,310,832)	8.79%
6		Fuel Cost of Power Sold (Per A6)	($59,931,294)	($51,392,408)	($8,538,886)	16.62%
7		Gains from Off-System Sales (Per A6)	($31,331,278)	($28,731,438)	($2,599,840)	9.05%
8		Fuel Cost of Purchased Power (Per A7)	$30,925,266	$32,322,589	($1,397,323)	(4.32%)
9		Energy Payments to Qualifying Facilities (Per A8)	$5,469,331	$5,851,938	($382,607)	(6.54%)
10		Energy Cost of Economy Purchases (Per A9)	$10,646,395	$24,020,472	($13,374,077)	(55.68%)
11		Total Fuel Costs & Net Power Transactions	$3,173,223,943	$3,016,510,670	$156,713,273	5.20%
12						
13	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$516,451	$519,261	($2,810)	(0.54%)
14		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$1,611,119	$1,375,890	$235,229	17.10%
15		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($151,215)	($417,954)	$266,739	(63.82%)
16		Total Incremental Optimization Costs	$1,976,355	$1,477,197	$499,158	33.79%
17						
18	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($1,150,732)	($390,023)	($760,709)	195.04%
19		Inventory Adjustments	$1,056,384	$629,547	$426,836	67.80%
20		Non Recoverable Oil/Tank Bottoms	$222,715	$222,715	$0	0.00%
21		Other O&M Expense	$571,371	$551,034	$20,337	3.69%
22		Adjusted Total Fuel Costs & Net Power Transactions	$3,175,900,036	$3,019,001,140	$156,898,896	5.20%
23						
24	**kWh Sales**	Jurisdictional kWh Sales	110,053,141,083	107,821,851,507	2,231,289,576	2.07%
25		Sales for Resale (excluding Stratified Sales)	5,730,700,050	5,100,512,972	630,187,078	12.36%
26		Sub-Total Sales	115,783,841,133	112,922,364,479	2,861,476,654	2.53%
27						
28		**Jurisdictional % of Total Sales (Line 24/26)**	95.05052%	95.48317%	77.97686%	81.67%
29						
30	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$2,867,598,717	$2,802,084,630	$65,514,087	2.34%
31						
32	**Fuel Adjustment Revenues Not Applicable to Period**					
33		Prior Period True-Up (Collected)/Refunded This Period [3]	$16,792,378	$16,792,378	$0	0.00%
34		GPIF, Net of Revenue Taxes [4]	($9,649,084)	($9,649,086)	$3	(0.00%)
35		Incentive Mechanism, Net of Revenue Taxes [5]	($9,526,193)	($9,526,193)	$0	0.00%
36		Jurisdictional Fuel Revenues Applicable to Period	$2,865,215,818	$2,799,701,728	$65,514,090	2.34%
37		Adjusted Total Fuel Costs & Net Power Transactions	$3,175,900,036	$3,019,001,140	$156,898,896	5.20%
38		Jurisdictional kWh Sales	95.05%	95.48%	77.98%	81.67%
39		Juris. Total Fuel Costs & Net Power Trans. (Line 37xLine38x1.00133)	$3,022,623,937	$2,886,505,885	$136,118,052	4.72%
40		True-Up Provision for the Month-Over/(Under) Recovery (Line 36- Line 39)	($157,408,119)	($86,804,157)	($70,603,962)	81.34%
41		Interest Provision for the Month	($1,353,535)	($1,304,092)	($49,443)	3.79%
42		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	$16,792,378	$16,792,378	$0	0.00%
43		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($23,632,267)	($23,632,267)	$0	0.00%
44		Prior Period True-Up Collected/(Refunded) This Period	($16,792,378)	($16,792,378)	$0	0.00%
45		End of Period Net True-up Amount Over/(Under) Recovery (Line 40 - Line 44)	($182,393,921)	($111,740,516)	($70,653,405)	63.23%
46						

47 [1] Actuals include various adjustments as noted on the A-Schedules.

48 [2] Other Fuel Expense consists of nuclear fuel design software maintenance costs.

49 [3] Prior Period 2017 Actual/Estimated True-up.

50 [4] Generating Performance Incentive Factor is (($9,656,036/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI.

51 [5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($9,533,057/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI.

52 [6] 2017 Final True-up.

REVISED 7/26/19

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

Line No.	Line	Total
1	End of Period True-Up (1)	$13,577,628
2	Less: Actual/Estimated True-Up for the same period (2)	$6,415,909
3	Net True Up for the Period	$7,161,719
4		
5	(1) From Page 4, Column (15), Lines 9 & 10.	
6	(2) Approved in FPSC Final Order PSC-2018-0610-FOF-EI.	
7		
8	Note: Totals may not add due to rounding	
9		
10	( ) Reflects Under-recovery	
11		
12		
13		
14		
15	Columnns and rows may not add due to rounding	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 19
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-6

REVISED 7/26/19
Docket No. 20190001-EI
2018 CCR Final True Up
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE FINAL TRUE-UP PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Capacity Costs	a-Jan - 2018	a-Feb - 2018	a-Mar - 2018	a-Apr - 2018	a-May - 2018	a-Jun - 2018	a-Jul - 2018	a-Aug - 2018	a-Sep - 2018	a-Oct - 2018	a-Nov - 2018	a-Dec - 2018	Total
1	**Base**													
2	Payments to Non-cogenerators	$901,301	($6,606,934)	$1,442,911	$1,195,029	$1,410,102	$1,030,047	$1,530,800	$1,530,800	$1,486,549	$1,221,016	$1,230,546	$1,822,519	$8,194,687
3	Payments to Co-generators	$813,328	($586,738)	$113,295	$113,295	$210,228	$13,908	$105,358	$123,686	$113,295	$113,295	$113,295	$113,295	$1,359,540
4	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$10,089,646	$10,059,421	$10,029,196	$9,998,971	$9,968,746	$9,938,520	$9,860,803	$9,831,191	$9,801,578	$9,771,966	$9,742,354	$9,712,741	$118,805,132
5	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($93,924)	($93,528)	($93,132)	($92,736)	($92,340)	($91,944)	($90,926)	($90,538)	($90,151)	($89,763)	($89,375)	($88,987)	($1,097,343)
6	Indiantown Transaction - Regulatory Asset - Amortization and Return	$6,777,143	$6,749,953	$6,722,764	$6,695,575	$6,668,385	$6,641,196	$6,564,669	$6,538,031	$6,511,393	$6,484,755	$6,458,116	$6,431,478	$79,243,457
7	SJRPP Revenue Requirements	$1,130,656	$1,119,275	$1,107,892	$1,096,511	$1,085,130	$1,073,749	$1,053,254	$1,042,104	$1,030,954	$1,019,803	$1,008,653	$997,503	$12,765,484
8	Incremental Plant Security Costs O&M	$2,422,840	$2,028,451	$2,104,429	$2,375,596	$2,020,784	$2,143,832	$2,241,615	$2,528,416	$2,125,567	$1,978,287	$2,223,730	$2,824,341	$27,017,888
9	Incremental Plant Security Costs Capital	$235,139	$238,990	$244,524	$251,374	$255,953	$259,239	$259,365	$262,637	$266,671	$270,312	$274,960	$282,652	$3,101,816
10	Incremental Nuclear NRC Compliance Costs O&M	$85,624	$285,960	$75,293	$135,846	$115,687	$188,256	$238,245	$177,111	$90,114	$66,389	$239,709	$210,187	$1,908,420
11	Incremental Nuclear NRC Compliance Costs Capital	$916,397	$926,618	$935,812	$935,279	$934,622	$932,512	$921,519	$925,829	$930,636	$943,971	$958,930	$967,372	$11,229,497
12	Transmission of Electricity by Others	$354,669	$22,654	$9,929	$1,303	$15,873	$34,071	($26,894)	$24		$21,154	($509,804)	($73,925)	($150,946)
13	Transmission Revenues from Capacity Sales	($1,504,513)	($971,822)	($1,192,732)	($526,107)	($1,114,919)	($426,142)	($570,975)	($316,283)	($522,375)	($556,476)	($827,736)	($900,414)	($9,430,493)
14	Total Base	$22,128,305	$13,172,301	$21,500,182	$22,179,936	$21,478,251	$21,737,246	$22,086,833	$22,553,007	$21,744,230	$21,244,709	$20,823,377	$22,298,761	$252,947,139
15														
16	**Intermediate**													
17	Incremental Plant Security Costs O&M	$40,553	$259,024	$227,888	$105,840	$97,773	$132,703	$133,730	$59,285	$76,059	$164,205	$128,266	$174,713	$1,600,039
18	Incremental Plant Security Costs Capital	$47,332	$47,232	$47,133	$47,034	$46,893	$46,751	$46,014	$45,918	$45,821	$45,725	$45,628	$45,531	$557,012
19	Total Intermediate	$87,885	$306,257	$275,021	$152,874	$144,665	$179,455	$179,744	$105,203	$121,880	$209,930	$173,894	$220,245	$2,157,052
20														
21	**Peaking**													
22	Incremental Plant Security Costs O&M	$22,301	$123,516	$57,732	$25,718	$22,861	$19,185	$21,583	$23,739	$16,513	$59,561	$51,362	$79,262	$523,334
23	Incremental Plant Security Costs Capital	$6,803	$6,784	$6,765	$6,746	$6,726	$6,707	$6,612	$6,594	$6,575	$6,556	$6,538	$6,519	$79,923
24	Total Peaking	$29,104	$130,300	$64,496	$32,464	$29,588	$25,892	$28,195	$30,333	$23,088	$66,117	$57,900	$85,781	$603,257
25														
26	**General**													
27	Incremental Plant Security Costs Capital	$2,971	$2,956	$2,940	$2,924	$2,908	$2,893	$2,868	$2,852	$2,837	$2,821	$2,806	$2,790	$34,566
28	Total General	$2,971	$2,956	$2,940	$2,924	$2,908	$2,893	$2,868	$2,852	$2,837	$2,821	$2,806	$2,790	$34,566
29														
30	**Total**	$22,248,265	$13,611,813	$21,842,639	$22,368,198	$21,655,413	$21,945,485	$22,297,639	$22,691,395	$21,892,035	$21,523,577	$21,057,977	$22,607,577	$255,742,014
31														
32	Totals may not add due to rounding													

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2018	a-Feb - 2018	a-Mar - 2018	a-Apr - 2018	a-May - 2018	a-Jun - 2018	a-Jul - 2018	a-Aug - 2018	a-Sep - 2018	a-Oct - 2018	a-Nov - 2018	a-Dec - 2018	Total
1														
2	Total Capacity Costs (Page 2, Line 30)	$22,248,265	$13,611,813	$21,842,639	$22,368,198	$21,655,413	$21,945,485	$22,297,639	$22,691,395	$21,892,035	$21,523,577	$21,057,977	$22,607,577	$255,742,014
3														
4	Total Base Capacity Costs	$22,128,305	$13,172,301	$21,500,182	$22,179,936	$21,478,251	$21,737,246	$22,086,833	$22,553,007	$21,744,230	$21,244,709	$20,823,377	$22,298,761	$252,947,139
5	Base Jurisdictional Factor [(a)]	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%
6	Total Base Jurisdictional Capacity Costs	$21,169,088	$12,601,309	$20,568,192	$21,218,480	$20,547,212	$20,794,979	$21,129,413	$21,575,379	$20,801,662	$20,323,794	$19,920,725	$21,332,155	$241,982,387
7														
8	Total Intermediate Capacity Costs	$87,885	$306,257	$275,021	$152,874	$144,665	$179,455	$179,744	$105,203	$121,880	$209,930	$173,894	$220,245	$2,157,052
9	Intermediate Jurisdictional Factor [(a)]	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%
10	Total Intermediate Jurisdictional Capacity Costs	$82,737	$288,319	$258,914	$143,920	$136,193	$168,944	$169,217	$99,041	$114,741	$197,635	$163,709	$207,345	$2,030,715
11														
12	Total Peaking Capacity Costs	$29,104	$130,300	$64,496	$32,464	$29,588	$25,892	$28,195	$30,333	$23,088	$66,117	$57,900	$85,781	$603,257
13	Peaking Jurisdictional Factor [(a)]	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%
14	Total Peaking Jurisdictional Capacity Costs	$27,573	$123,444	$61,103	$30,756	$28,031	$24,530	$26,711	$28,737	$21,873	$62,638	$54,854	$81,267	$571,518
15														
16	Solar Jurisdictional Factor [(a)]	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%
17														
18	Transmission Jurisdictional Factor	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%
19														
20	Total General Capacity Costs	$2,971	$2,956	$2,940	$2,924	$2,908	$2,893	$2,868	$2,852	$2,837	$2,821	$2,806	$2,790	$34,566
21	General Jurisdictional Factor [(a)]	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%
22	Total General Jurisdictional Capacity Costs	$2,881	$2,865	$2,850	$2,835	$2,819	$2,804	$2,780	$2,765	$2,750	$2,735	$2,720	$2,705	$33,510
23														
24	Jurisdictional Capacity Costs	$21,282,278	$13,015,938	$20,891,058	$21,395,991	$20,714,255	$20,991,258	$21,328,121	$21,705,922	$20,941,026	$20,586,802	$20,142,008	$21,623,472	$244,618,130
25														
26	Nuclear Cost Recovery Costs	($665,337)	($669,748)	($674,209)	($678,722)	($683,296)	($687,940)	($692,666)	($697,499)	($702,476)	($707,674)	($713,284)	($985,444)	($8,558,295)
27														
28	Net Jurisdictional Capacity Costs	$20,616,942	$12,346,189	$20,216,850	$20,717,268	$20,030,959	$20,303,318	$20,635,454	$21,008,423	$20,238,550	$19,879,128	$19,428,724	$20,638,029	$236,059,835
29														
30														
31														
32	[(a)] As approved in Order No. PSC-2018-0610-FOF-EI.													
33														
34	Totals may not add due to rounding													

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2018	a-Feb - 2018	a-Mar - 2018	a-Apr - 2018	a-May - 2018	a-Jun - 2018	a-Jul - 2018	a-Aug - 2018	a-Sep - 2018	a-Oct - 2018	a-Nov - 2018	a-Dec - 2018	Total
1														
2	Net Jurisdictional CCR Costs (Page 3, Line 28)	$20,616,942	$12,346,189	$20,216,850	$20,717,268	$20,030,959	$20,303,318	$20,635,454	$21,008,423	$20,238,550	$19,879,128	$19,428,724	$20,638,029	$236,059,835
3														
4	CCR Revenues (Net of Revenue Taxes)	$20,939,641	$19,614,735	$17,854,813	$18,654,560	$20,286,676	$21,810,960	$21,952,605	$22,617,217	$21,584,076	$21,879,317	$19,159,809	$16,986,220	$243,340,629
5	Prior Period True-up Provision	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$937,222
6	Cape Canaveral GBRA Refund	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$5,155,918
7	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	21,447,403	20,122,496	18,362,575	19,162,322	20,794,437	22,318,722	22,460,366	23,124,979	22,091,838	22,387,078	19,667,571	17,493,982	249,433,769
8														
9	True-up Provision - Over/(Under) Recovery (Line 7 - Line 2)	$830,461	$7,776,307	($1,854,275)	($1,554,946)	$763,478	$2,015,404	$1,824,912	$2,116,555	$1,853,288	$2,507,951	$238,847	($3,144,047)	$13,373,935
10	Interest Provision	$5,120	$10,064	$14,943	$12,534	$11,157	$12,976	$15,734	$18,174	$21,839	$26,515	$28,747	$25,891	$203,693
11	True-up & Interest Provision Beginning of Year - Over/(Under) Recovery	$6,093,140	$6,420,959	$13,699,569	$11,352,476	$9,302,302	$9,569,175	$11,089,793	$12,422,677	$14,049,644	$15,417,009	$17,443,713	$17,203,545	$6,093,140
12	Deferred True-up - Over/(Under) Recovery	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)
13	GBRA Refund Cape Canaveral	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($5,155,918)
14	Prior Period True-up Provision - Collected/(Refunded)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($937,222)
15	End of Period True-up - Over/(Under) Recovery (Lines 9 through 14)	$4,208,153	$11,486,762	$9,139,669	$7,089,495	$7,356,368	$8,876,986	$10,209,870	$11,836,837	$13,204,202	$15,230,906	$14,990,738	$11,364,821	$11,364,821
16														
17	Totals may not add due to rounding													

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

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

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

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Line	CCR 2018 Final True-up	CCR 2018 Actual/Estimated	Dif. CCR - 2018 Actual/Estimated	% Dif. CCR - 2018 Actual/Estimated
1	Total Capacity Costs	$255,742,014	$259,644,143	($3,902,129)	(1.50%)
2					
3	Total Base Capacity Costs	$252,947,139	$257,240,683	($4,293,544)	(1.67%)
4	Base Jurisdictional Factor	95.66520%	95.66520%		
5	Total Base Jurisdictionalized Capacity Costs	$241,982,387	$246,089,814	($4,107,427)	(1.67%)
6					
7	Total Intermediate Capacity Costs	$2,157,052	$1,829,989	$327,063	17.87%
8	Intermediate Jurisdictional Factor	94.14%	94.14310%		
9	Total Intermediate Jurisdictionalized Capacity Costs	$2,030,715	$1,722,808	$307,907	17.87%
10					
11	Total Peaking Capacity Costs	$603,257	$538,905	$64,352	11.94%
12	Peaking Jurisdictional Factor	94.73860%	94.73860%		
13	Total Peaking Jurisidictionalized Capacity Costs	$571,518	$510,551	$60,966	11.94%
14					
15	Total Solar Capacity Costs	$0	$0	$0	N/A
16	Solar Jurisdictional Factor	95.66520%	95.66520%		
17	Total Solar Jurisdictionalized Capacity Costs	$0	$0	$0	0.00%
18					
19	Total General Capacity Costs	$34,566	$34,566	$0	N/A
20	General Jurisdictional Factor	96.94490%	96.94490%		
21	Total General Jurisdictionalized Capacity Costs	$33,510	$33,510	$0	0.00%
22					
23	Total Transmission Capacity Costs	$0	$0	$0	N/A
24	Transmission Jurisdictional Factor	88.79740%	88.79740%		
25	Total Transmission Jurisdictionalized Costs	$0	$0	$0	0.00%
26					
27	Jurisdictional Capacity Costs	$244,618,130	$248,356,683	($3,738,553)	(1.51%)
28					
29	Nuclear Cost Recovery Costs	($8,558,295)	($8,295,198)	($263,097)	3.17%
30					
31	Net Jurisdictional Capacity Costs	$236,059,835	$240,061,486	($4,001,651)	1.67%
32					
33	CCR Revenues	$243,340,629	$240,213,606	$3,127,023	1.3%
34	Prior Period True-up Provision	$937,222	$937,222	$0	N/A
35	Cape Canaveral GBRA Refund	$5,155,918	$5,155,918	$0	N/A
36	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$249,433,769	$246,306,746	$3,127,023	1.3%
37					
38	True-up Provision for Month - Over/(Under) Recovery	$13,373,935	$6,245,260	$7,128,674	114.15%
39	Interest Provision for the Month	$203,693	$170,648	$33,045	19.36%
40	True-Up & Interest Provision - Beginning of Year	$6,093,140	$6,093,140	$0	N/A
41	Deferred True-up - Over/(Under) Recovery	($2,212,807)	($2,212,807)	$0	N/A
42	GBRA Refund Cape Canaveral	($5,155,918)	($5,155,918)	$0	N/A
43	Prior Period True-up Provision - Collected/(Refunded) this Month	($937,222)	($937,222)	$0	N/A
44	End of Period True-up - Over/(Under) Recovery	$11,364,821	$4,203,102	$7,161,719	170.4%
45					
46	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 2018 THROUGH DECEMBER 2018

Line No.	Strata	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	**Base**	Investments														
2		a.Expenditures/Additions		$543,088	$636,293	($1,851,701)	($42,249)	$400,554	$653,721	$519,658	$618,648	$757,403	$518,920	$1,106,460	$1,459,719	$5,320,512
3		b.Clearings to Plant		$44,524	$54,376	$2,134,361	$349,738	$29,205	$25,602	$19,816	$29,445	$19,567	$11,044	($8,393)	$17,062	$2,726,348
4		c.Retirements														
5		d.Other		$156	$9,265	($523)	($554)	($865)	($5,447)	($4,723)	$794	$811	($4,991)	($10,436)	($12,408)	($28,923)
6																
7		Plant-In-Service/Depreciation Base	$16,498,724	$16,543,248	$16,597,624	$18,731,985	$19,081,723	$19,110,928	$19,136,530	$19,156,346	$19,185,792	$19,205,358	$19,216,403	$19,208,010	$19,225,071	N/A
8		Less: Accumulated Depreciation	$617,968	$699,344	$790,084	$873,972	$963,323	$1,055,134	$1,142,625	$1,231,016	$1,324,994	$1,419,081	$1,507,424	$1,590,328	$1,671,272	N/A
9		CWIP - Non Interest Bearing	$7,532,118	$8,075,206	$8,711,499	$6,859,797	$6,817,549	$7,218,102	$7,871,824	$8,391,481	$9,010,130	$9,767,532	$10,286,452	$11,392,912	$12,852,631	N/A
10																
11		Net Investment (Lines 7 - 8 + 9)	$23,412,874	$23,919,110	$24,519,039	$24,717,810	$24,935,949	$25,273,897	$25,865,729	$26,316,811	$26,870,928	$27,553,810	$27,995,431	$29,010,593	$30,406,430	N/A
12																
13		Average Net Investment		$23,665,992	$24,219,074	$24,618,425	$24,826,880	$25,104,923	$25,569,813	$26,091,270	$26,593,869	$27,212,369	$27,774,621	$28,503,012	$29,708,512	N/A
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes [a]		$127,464	$130,443	$132,594	$133,717	$135,214	$137,718	$137,340	$139,985	$143,241	$146,200	$150,035	$156,380	$1,670,332
17		b.Debt Component (Line 13 x debt rate x 1/12) [b]		$26,454	$27,072	$27,518	$27,751	$28,062	$28,582	$28,912	$29,469	$30,154	$30,777	$31,584	$32,920	$349,256
18																
19		Investment Expenses														
20		a.Depreciation		$81,221	$81,475	$84,411	$89,905	$92,676	$92,939	$93,114	$93,183	$93,276	$93,334	$93,341	$93,352	$1,082,227
21		b.Amortization														
22		c.Other														
23																
24		Total System Recoverable Costs (Lines 15 & 19)		$235,139	$238,990	$244,524	$251,374	$255,953	$259,239	$259,365	$262,637	$266,671	$270,312	$274,960	$282,652	$3,101,816
25																
26																
27																

28 [a] The monthly Equity Component for the Jan. - Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component
29 for the Jul. - Dec. 2017 period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

30 [b] The Debt Component for the Jan. - Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI, and the Debt Component for the Jul. - Dec. 2017 period is 1.3413%
31 based on the May 2017 ROR Surveillance Report and reflects a 10.55% ROE, per FPSC Order No. PSC-2016-0560-PAA-EI.

32

33 Totals may not add due to rounding

REVISED 7/26/19
Docket No. 20190001-EI
2018 CCR Final True Up
Exhibit RBD-6, Page 7 of 8

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY
Return on Capital Investments, Depreciation and Taxes
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Strata	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	**General**	Investments														
2		a.Expenditures/Additions														
3		b.Clearings to Plant														
4		c.Retirements														
5		d.Other														
6																
7		Plant-In-Service/Depreciation Base	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	N/A
8		Less: Accumulated Depreciation	$59,518	$61,940	$64,361	$66,782	$69,204	$71,625	$74,047	$76,468	$78,889	$81,311	$83,732	$86,154	$88,575	N/A
9		CWIP - Non Interest Bearing														N/A
10																
11		Net Investment (Lines 7 - 8 + 9)	$85,766	$83,344	$80,923	$78,501	$76,080	$73,659	$71,237	$68,816	$66,394	$63,973	$61,552	$59,130	$56,709	N/A
12																
13		Average Net Investment		$84,555	$82,134	$79,712	$77,291	$74,869	$72,448	$70,027	$67,605	$65,184	$62,762	$60,341	$57,920	N/A
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes [(a)]		$455	$442	$429	$416	$403	$390	$369	$356	$343	$330	$318	$305	$4,557
17		b.Debt Component (Line 13 x debt rate x 1/12) [(b)]		$95	$92	$89	$86	$84	$81	$78	$75	$72	$70	$67	$64	$952
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	$2,421	$29,057
21		b.Amortization														
22		c.Other														
23																
24		Total System Recoverable Costs (Lines 15 & 19)		$2,971	$2,956	$2,940	$2,924	$2,908	$2,893	$2,868	$2,852	$2,837	$2,821	$2,806	$2,790	$34,566
25																
26																

27 [(a)] The monthly Equity Component for the Jan. - Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component
28 for the Jul. - Dec. 2017 period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.
29 [(b)] The Debt Component for the Jan. - Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI, and the Debt Component for the Jul. - Dec. 2017 period is 1.3413%
30 based on the May 2017 ROR Surveillance Report and reflects a 10.55% ROE, per FPSC Order No. PSC-2016-0560-PAA-EI.
31
33 Totals may not add due to rounding

REVISED 7/26/19
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2018 CCR Final True Up
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FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH APRIL 2020

(1)	(2)	(3)	(4)	(5)
Line No.		Dollars	MWH	Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$2,638,766,889	122,879,823	2.1474
2	Solar Base Rate Adjustment (SoBRA) Fuel Savings - 2020 Project	$11,149,004	122,879,823	0.0091
3	SolarTogether (ST) Credit	$31,975,895		N/A
4	Fuel Cost of Stratified Sales	($23,890,327)	(1,018,036)	2.3467
5	Rail Car Lease (Cedar Bay/Indiantown)	$1,887,737		N/A
6	Adjustments to Fuel Cost	$569,484		N/A
7	TOTAL COST OF GENERATED POWER	$2,660,458,682	121,861,787	2.1832
8	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	28,080,418	1,487,171	1.8882
9	Energy Cost of Economy Purchases (Per E9)	$12,462,935	521,230	2.3911
10	Energy Payments to Qualifying Facilities (Per E8)	$4,967,246	276,013	1.7996
11	TOTAL COST OF PURCHASED POWER	$45,510,599	2,284,414	1.9922
12	TOTAL AVAILABLE MWH (LINE 7 + LINE 11)		124,146,201	
13	Fuel Cost of Economy and Other Power Sales (E6)	($44,131,343)	(2,392,590)	1.8445
14	Gains from Off-System Sales (Per E6)	($22,134,432)		N/A
15	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($3,095,400)	(631,766)	0.4900
16	TOTAL FUEL COST AND GAINS OF POWER SALES	($69,361,175)	(3,024,356)	2.2934
17	Incremental Personnel, Software, and Hardware Costs	$463,695		N/A
18	Variable Power Plant O&M Attributable to Off-System Sales (Per E6)	$1,555,184		N/A
19	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	($338,800)		N/A
20	Total Incremental Optimization Costs	$1,680,079		
21	Total Fuel Costs & Net Power Transactions (Lines 7 + 11 +16 + 20)	$2,638,288,185	121,121,844	2.1782
22	Net Unbilled Sales [1]	$2,187,973	100,448	0.0019
23	Company Use [1]	$2,638,288	121,122	0.0023
24	T & D Losses [1]	$113,446,392	5,208,239	0.0981
25	System MWH Sales (Excluding Stratified Sales)	$2,638,288,185	115,692,035	2.2804
26	Wholesale MWH Sales (Excluding Stratified Sales)	$111,484,033	4,888,711	2.2804
27	Jurisdictional MWH Sales	$2,526,804,152	110,803,324	2.2804
28	Jurisdictional Loss Multiplier	$3,335,381		1.00132
29	Jurisdictional MWH Sales Adjusted for Line Losses	$2,530,139,533	110,803,324	2.2835
30	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	($58,082,532)	110,803,324	(0.0524)
31	TOTAL JURISDICTIONAL FUEL COST	$2,472,057,001	110,803,324	2.2311
32	Revenue Tax Factor	1,779,881		1.00072
33	Fuel Factor Adjusted for Taxes	$2,473,836,882	110,803,324	2.2327
34	GPIF [2]	$8,577,071	110,803,324	0.0077
35	Jurisdictional Incentive Mechanism - FPL Portion	$12,786,460	110,803,324	0.0115
36	Fuel Factor Adjusted for GPIF (Lines 33 through 35)	$2,495,200,413	110,803,324	2.2519
37	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			2.252
38				
39	[1] For informational purposes only			
40	[2] Caluculation based on Jurisdictional KWH sales			
41				
42	Note: Totals may not add due to rounding.			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 20
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-7

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)

SCHEDULE: E1-A

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

Line No.		Annual Total
1	Actual/Estimated over/(under) recovery [1]	$128,735,937
2	Final over/(under) recovery [2]	($70,653,405)
3	Total over/(under) recovery to be included in projected period [3]	$58,082,532
4		
5	Total Jurisdictional Sales (MWH)	110,803,324
6		
7	True-Up Factor (cents/kWh)	0.0524
8		
9	Note: Totals may not add due to rounding.	
10		
11	[1] Actual/Estimated over/(under) recovery for January 2019 - December 2019	
12	[2] Final True-up over/(under) recovery for January 2018 - December 2018	
13	[3] Projected Period January 2020 - December 2020 (Schedule E1, Line 30)	
14		
15	Note: Totals may not add due to rounding.	

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FLORIDA POWER & LIGHT COMPANY
CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR

SCHEDULE: E1-C

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

Line No.		Annual Total
1	TOTAL AMOUNT OF ADJUSTMENTS	($36,719,001)
2	A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$8,577,071
3	B. TRUE-UP (OVER)/UNDER RECOVERED	($58,082,532)
4	C. JURISDICTIONALIZED INCENTIVE MECHANISM - FPL PORTION	$12,786,460
5		
6	TOTAL JURISDICTIONAL SALES (MWH)	110,803,324
7		
8	ADJUSTMENT FACTORS (cents/kWh)	(0.0331)
9	A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0077
10	B. TRUE-UP FACTOR	(0.0524)
11	C. JURISDICTIONALIZED INCENTIVE MECHANISM - FPL PORTION	0.0115
12		
13	Note: Totals may not add due to rounding.	
14		
15	Note: Totals may not add due to rounding.	

FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2020 THROUGH DECEMBER 2020

Line No.	CALCULATION OF JURISDICTIONAIZED 2018 Incentive Mechanism Gains - FPL Portion		Annual Total
1	2018 Incentive Mechanism Gains - FPL Portion [(a)]		$13,442,599
2			
3	2018 Actual \Retail kWh sales		110,053,141
4	2018 Actual Total System kWh sales		115,783,841
5	2018 Actual Average Jurisdictional % [(b)]		95.05052%
6			
7	Jurisdictionalized 2018 Incentive Mechanism Gains - FPL Portion	$	12,777,260
8			
9	Revenue Tax Factor		1.00072
10			
11	Jurisdictionalized 2018 Incentive Mechanism Gains - FPL Portion Adjusted for Revenue Taxes	$	12,786,460
12			
13	2020 Projected kWh Sales		110,803,324
14			
15	2018 Jurisdictional Incentive Mechanism Gains - FPL Portion for Recovery in 2020 CENTS/KWH	$	0.0115
16			
17	[(a)] Reflected on Exhibit GJY-1, filed on March 1, 2019		
18	[(b)] Reflected on Schedule E1-B, filed on March 1, 2019		
19			
20			
21			
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FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF SEASONALLY DIFFERENTIATED TIME OF USE MULTIPLIERS

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	E1-D Schedule	Marginal Cost	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	On-Peak Period	System MWH Requirements	4,880,225	4,315,732	4,683,313	6,562,651	6,438,209	7,752,295	8,191,986	8,001,541	7,355,893	7,218,381	4,341,688	4,504,093	74,246,006
2		Marginal Cost	89,407,182	79,343,006	80,952,478	117,697,856	119,229,198	152,704,708	179,076,806	190,794,340	171,336,401	158,766,123	85,991,034	84,951,699	1,510,250,831
3		Average Marginal Cost (¢/kWh)	1.832	1.838	1.729	1.793	1.852	1.970	2.186	2.384	2.329	2.199	1.981	1.886	2.034
4															
5	Off-Peak Period	System MWH Requirements	13,612,826	12,853,517	14,117,656	12,650,979	15,176,970	15,056,965	16,247,620	16,540,213	15,351,404	14,019,154	13,783,506	13,331,967	172,742,778
6		Marginal Cost	220,015,939	212,397,938	232,040,623	195,391,844	241,436,760	245,860,663	274,389,807	287,192,688	261,227,163	239,644,827	233,429,191	217,721,683	2,860,749,126
7		Average Marginal Cost (¢/kWh)	1.616	1.652	1.644	1.544	1.591	1.633	1.689	1.736	1.702	1.709	1.694	1.633	1.656
8															
9	Total Period	System MWH Requirements	18,493,051	17,169,249	18,800,970	19,213,630	21,615,179	22,809,260	24,439,606	24,541,754	22,707,297	21,237,535	18,125,194	17,836,060	246,988,784
10		Marginal Cost	309,423,121	291,740,945	312,993,101	313,089,700	360,665,957	398,565,371	453,466,612	477,987,028	432,563,563	398,410,951	319,420,225	302,673,382	4,370,999,957
11		Average Marginal Cost (¢/kWh)	1.673	1.699	1.665	1.630	1.669	1.747	1.855	1.948	1.905	1.876	1.762	1.697	1.770
12															
13	On-Peak Period	Marginal Fuel Cost Weighting Multiplier													1.149
14	Off-Peak Period	Marginal Fuel Cost Weighting Multiplier													0.936
15	Average	Marginal Fuel Cost Weighting Multiplier													1.000
16															
17															
18	Note: Totals may not add due to rounding.														

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FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF TIME OF USE MULTIPLIERS FOR SEASONAL DEMAND TIME OF USE RIDER

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	E1-D Schedule	SDTR	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Total
1	On-Peak Period	System MWH Requirements	2,679,187	2,963,819	2,774,301	2,623,992	11,041,300
2		Marginal Cost	55,874,717	72,336,753	80,888,087	71,175,258	280,274,815
3		Average Marginal Cost (¢/kWh)	2.086	2.441	2.916	2.712	2.538
4							
5	Off-Peak Period	System MWH Requirements	20,130,073	21,475,786	21,767,453	20,083,305	83,456,617
6		Marginal Cost	340,037,189	377,497,077	393,363,993	357,685,666	1,468,583,925
7		Average Marginal Cost (¢/kWh)	1.689	1.758	1.807	1.781	1.760
8							
9	Total Period	System MWH Requirements	22,809,260	24,439,606	24,541,754	22,707,297	94,497,917
10		Marginal Cost	395,911,906	449,833,829	474,252,081	428,860,924	1,748,858,740
11		Average Marginal Cost (¢/kWh)	1.736	1.841	1.932	1.889	1.851
12							
13	On-Peak Period	Marginal Fuel Cost Weighting Multiplier					1.372
14	Off-Peak Period	Marginal Fuel Cost Weighting Multiplier					0.951
15	Average	Marginal Fuel Cost Weighting Multiplier					1.000
16							
17	Note: Totals may not add due to rounding.						

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FLORIDA POWER & LIGHT COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH APRIL 2020

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	GROUPS	RATE SCHEDULE	JANUARY - APRIL		
			Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	A	RS-1 first 1,000 kWh	2.252	1.00212	1.925
2	A	RS-1 all additional kWh	2.252	1.00212	2.925
3					
4	A	GS-1, SL-2, GSCU-1, WIES-1	2.252	1.00212	2.257
5					
6	A-1	SL-1, OL-1, PL-1 [1]	2.185	1.00212	2.190
7					
8	B	GSD-1	2.252	1.00207	2.257
9					
10	C	GSLD-1, CS-1	2.252	1.00157	2.256
11					
12	D	GSLD-2, CS-2, OS-2, MET	2.252	0.99555	2.242
13					
14	E	GSLD-3, CS-3	2.252	0.97529	2.196
15					
16	A	GST-1 On-Peak	2.588	1.00212	2.593
17	A	GST-1 Off-Peak	2.108	1.00212	2.112
18					
19	A	RTR-1 On-Peak			0.336
20		RTR-1 Off-Peak			(0.145)
21					
22	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	2.588	1.00207	2.593
23	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.108	1.00207	2.112
24					
25	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	2.588	1.00157	2.592
26	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.108	1.00157	2.111
27					
28	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	2.588	0.99588	2.577
29	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.108	0.99588	2.099
30					
31	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	2.588	0.97529	2.524
32	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.108	0.97529	2.056
33					
34	F	CILC-1(D), ISST-1(D) On-Peak	2.588	0.99566	2.577
35		CILC-1(D), ISST-1(D) Off-Peak	2.108	0.99566	2.099
36					
37	[1] WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK				
38					
39	Note: Totals may not add due to rounding.				

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH APRIL 2020

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER		
			Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	B	GSD(T)-1 On-Peak	3.090	1.00207	3.096
2		GSD(T)-1 Off-Peak	2.142	1.00207	2.146
3					
4	C	GSLD(T)-1 On-Peak	3.090	1.00157	3.095
5		GSLD(T)-1 Off-Peak	2.142	1.00157	2.145
6					
7	D	GSLD(T)-2 On-Peak	3.090	0.99588	3.077
8		GSLD(T)-2 Off-Peak	2.142	0.99588	2.133
9					
10	Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm				
11	Off Peak Period is defined as all other hours.				
12					
13	Note: All other months served under the otherwise applicable rate schedule.				
14	See Schedule E-1E, Page 1 of 2.				
15					
16	Note: Totals may not add due to rounding.				

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Rate Class/Voltage Level	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	**RS(T)-1**						
2	**Secondary**	59,480,243	1.04537	62,178,764	0.95660	2,698,520	
3	TOTAL	59,480,243	1.04537	62,178,764	0.95660	2,698,520	1.00212
4							
5	**CILC-1D**						
6	**Primary**	1,049,867	1.02881	1,080,110	0.97200	30,243	
7	**Secondary**	1,532,432	1.04537	1,601,956	0.95660	69,524	
8	TOTAL	2,582,298	1.03864	2,682,066	0.96280	99,767	0.99566
9							
10	**CILC-1G**						
11	**Primary**	2,115	1.02881	2,176	0.97200	61	
12	**Secondary**	101,481	1.04537	106,085	0.95660	4,604	
13	TOTAL	103,595	1.04503	108,260	0.95691	4,665	1.00179
14							
15	**CILC-1T**						
16	**Transmission**	1,372,962	1.01738	1,396,827	0.98291	23,865	
17	TOTAL	1,372,962	1.01738	1,396,827	0.98291	23,865	0.97529
18							
19	**GS(T)-1**						
20	**Secondary**	6,321,078	1.04537	6,607,855	0.95660	286,777	
21	TOTAL	6,321,078	1.04537	6,607,855	0.95660	286,777	1.00212
22							
23	**GSCU-1**						
24	**Secondary**	96,909	1.04537	101,306	0.95660	4,397	
25	TOTAL	96,909	1.04537	101,306	0.95660	4,397	1.00212
26							
27	**GSD(T)-1**						
28	**Primary**	80,748	1.02881	83,074	0.97200	2,326	
29	**Secondary**	27,106,027	1.04537	28,335,783	0.95660	1,229,756	
30	TOTAL	27,186,775	1.04532	28,418,857	0.95665	1,232,082	1.00207
31							
32	**GSLD(T)-1**						
33	**Primary**	343,568	1.02881	353,465	0.97200	9,897	
34	**Secondary**	9,638,126	1.04537	10,075,392	0.95660	437,266	
35	TOTAL	9,981,694	1.04480	10,428,857	0.95712	447,163	1.00157
36							
37	**GSLD(T)-2**						
38	**Primary**	1,008,665	1.02881	1,037,722	0.97200	29,056	
39	**Secondary**	1,559,700	1.04537	1,630,461	0.95660	70,761	
40	TOTAL	2,568,366	1.03886	2,668,183	0.96259	99,818	0.99588
41							
42	**GSLD(T)-3**						
43	**Transmission**	312,441	1.01738	317,872	0.98291	5,431	
44	TOTAL	312,441	1.01738	317,872	0.98291	5,431	0.97529
45							
46	**MET**						
47	**Primary**	80,480	1.02881	82,799	0.97200	2,318	
48	TOTAL	80,480	1.02881	82,799	0.97200	2,318	0.98624
49							
50	**OL-1**						
51	**Secondary**	95,152	1.04537	99,469	0.95660	4,317	
52	TOTAL	95,152	1.04537	99,469	0.95660	4,317	1.00212
53							
54	**OS-2**						
55	**Primary**	11,408	1.02881	11,737	0.97200	329	
56	TOTAL	11,408	1.02881	11,737	0.97200	329	0.98624
57							

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Rate Class/Voltage Level	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	**SL-1**						
2	**Secondary**	524,391	1.04537	548,182	0.95660	23,791	
3	TOTAL	524,391	1.04537	548,182	0.95660	23,791	1.00212
4							
5	**SL-2**						
6	**Secondary**	30,295	1.04537	31,670	0.95660	1,374	
7	TOTAL	30,295	1.04537	31,670	0.95660	1,374	1.00212
8							
9	**SL-1M**						
10	**Secondary**	5,938	1.04537	6,207	0.95660	269	
11	TOTAL	5,938	1.04537	6,207	0.95660	269	1.00212
12							
13	**SL-2M**						
14	**Secondary**	993	1.04537	1,038	0.95660	45	
15	TOTAL	993	1.04537	1,038	0.95660	45	1.00212
16							
17	**SST-DST**						
18	**Primary**	1,891	1.02881	1,946	0.97200	54	
19	**Secondary**	154	1.04537	161	0.95660	7	
20	TOTAL	2,045	1.03005	2,107	0.97082	61	0.98743
21							
22	**SST-TST**						
23	**Transmission**	83,464	1.01738	84,915	0.98291	1,451	
24	TOTAL	83,464	1.01738	84,915	0.98291	1,451	0.97529
25							
26	**TOTAL FPSC**						
27	TOTAL	110,840,531	1.04454	115,776,970	0.95736	4,936,440	1.00132
28							
29	**FKEC**						
30	**Transmission**	720,230	1.01738	732,749	0.98291	12,519	
31	TOTAL	720,230	1.01738	732,749	0.98291	12,519	0.97529
32							
33	**FPUC (INT)**						
34	**Transmission**	79,857	1.01738	81,245	0.98291	1,388	
35	TOTAL	79,857	1.01738	81,245	0.98291	1,388	0.97529
36							
37	**FPUC (PEAK)**						
38	**Transmission**	75,753	1.01738	77,070	0.98291	1,317	
39	TOTAL	75,753	1.01738	77,070	0.98291	1,317	0.97529
40							
41	**LCEC**						
42	**Transmission**	4,171,267	1.01738	4,243,772	0.98291	72,505	
43	TOTAL	4,171,267	1.01738	4,243,772	0.98291	72,505	0.97529
44							
45	**MOORE HAVEN**						
46	**Transmission**	28	1.01738	29	0.98291	0	
47	TOTAL	28	1.01738	29	0.98291	0	0.97529
48							
49	**NEW SMRYNA BCH (PEAK)**						
50	**Transmission**	12,129	1.01738	12,340	0.98291	211	
51	TOTAL	12,129	1.01738	12,340	0.98291	211	0.97529
52							
53	**New Smryna Beach**						
54	**Transmission**	360	1.01738	367	0.98291	6	
55	TOTAL	360	1.01738	367	0.98291	6	0.97529
56							
57							

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Rate Class/Voltage Level	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	**Quincy**						
2	**Transmission**	152	1.01738	155	0.98291	3	
3	TOTAL	152	1.01738	155	0.98291	3	0.97529
4							
5	**SEMINOLE**						
6	**Transmission**	850,842	1.01738	865,632	0.98291	14,789	
7	TOTAL	850,842	1.01738	865,632	0.98291	14,789	0.97529
8							
9	**WAUCHULA**						
10	**Transmission**	92	1.01738	94	0.98291	2	
11	TOTAL	92	1.01738	94	0.98291	2	0.97529
12							
13	**TOTAL FERC**						
14	TOTAL	5,911,167	1.01738	6,013,916	0.98291	102,748	0.97529
15							
16	**Total Company**						
17	TOTAL	116,751,698	1.04316	121,790,886	0.95862	5,039,188	
18							
19	**Company Use**						
20	TOTAL	134,335	1.04537	140,430	0.95660	6,095	
21							
22	**Total FPL**						
23	TOTAL	116,886,033	1.04316	121,931,316	0.95862	5,045,283	
24							
25	**HOMESTEAD (INT)**						
26	**Transmission**	216	1.01738	220	0.98291	4	
27	TOTAL	216	1.01738	220	0.98291	4	0.97529
28							
29	**NEW SMYRNA BCH (INT)**						
30	**Transmission**	240	1.01738	244	0.98291	4	
31	TOTAL	240	1.01738	244	0.98291	4	0.97529
32							
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	RATE CLASS GROUPS	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	GSD1/GSDT1/HLFT1	27,186,775	1.045319	28,418,857	0.956646	1,232,082	1.00207
2	GSLD1/GSLDT1/CS1/CST1/HLFT2	9,981,694	1.044798	10,428,857	0.957123	447,163	1.00157
3	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,568,366	1.038864	2,668,183	0.962590	99,818	0.99588
4	GSLD3/GSLDT3/CS3/CST3	312,441	1.017382	317,872	0.982915	5,431	0.97528
5	CILC D/CILC G	2,685,894	1.038882	2,790,326	0.962573	104,432	0.99589
6	OL1/SL1/SL1M/PL1	625,481	1.045368	653,858	0.956601	28,377	1.00211
7	SL2/SL2M/GSCU1	128,198	1.045368	134,014	0.956601	5,816	1.00211
8	GSD-1/GSDT-1/HLFT-1/SDTR-1/CILC-1G	27,290,371	1.045318	28,527,117	0.956647	1,236,747	1.00206
9	GSLDT-2/CS-2/HLFT-3/SDTR-3/OS-2/MET	2,660,254	1.038517	2,762,718	0.962912	102,465	0.99555
10	GSLD-3/GSLDT-3/CS-3/CST-3/CILC-1T	1,685,403	1.017382	1,714,699	0.982915	29,296	0.97528

FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH APRIL 2020

(1)	(2)	(3)	(4)	(5)	(6)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	39,695,440,896	0.019246	$763,976,852.12	1.925
2	All Additional KWH	19,764,836,314	0.029246	$578,041,604.51	2.925
3	Total KWH	59,460,277,210		$1,342,018,456.63	
4					
5	Avg Fuel Factor	2.252			
6	RS-1 Loss Multiplier	1.00212			
7	Average Fuel Factor	2.257			
8					
9	Target Fuel Revenues	$1,342,018,456.63			

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH APRIL 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1	Fuel Cost of System Net Generation (E3)	$201,318,532	$189,937,316	$201,267,387	$198,428,808	$222,524,843	$232,822,382	$252,047,102	$257,121,888	$236,291,294	$232,887,934	$202,699,881	$211,419,521	$2,638,766,889
2	Fuel Cost of Stratified Sales	($593,569)	($1,641,532)	($1,434,388)	($2,480,343)	($928,903)	($2,516,763)	($3,059,438)	($2,924,565)	($2,763,202)	($2,559,521)	($1,938,380)	($1,049,723)	($23,890,327)
3	Rail Car Lease (Cedar Bay/Indiantown)	$157,683	$157,683	$155,772	$157,683	$157,046	$157,683	$157,046	$157,683	$157,683	$157,046	$157,683	$157,046	$1,887,737
4	Solar Base Rate Adjustment (SoBRA) Fuel Savings - 2020 Project	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$11,149,004
5	Fuel Cost of Power Sold (Per E6)	($8,142,866)	($6,766,726)	($5,592,651)	($3,361,788)	($2,980,111)	($2,216,016)	($2,389,251)	($2,035,439)	($2,170,176)	($2,135,463)	($3,886,299)	($5,549,957)	($47,226,744)
6	Gains from Off-System Sales (Per E6)	($5,037,624)	($3,604,903)	($2,353,195)	($1,566,000)	($1,338,828)	($992,640)	($1,008,244)	($703,080)	($913,500)	($865,830)	($1,470,600)	($2,279,988)	($22,134,432)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$2,553,052	$2,312,893	$2,321,578	$2,412,083	$1,920,771	$2,468,579	$2,362,951	$2,501,975	$2,229,274	$2,365,614	$2,550,309	$2,081,340	$28,080,418
8	Energy Payments to Qualifying Facilities (Per E8)	$483,244	$377,184	$367,297	$332,150	$437,131	$402,842	$313,432	$348,297	$403,932	$577,582	$447,344	$476,813	$4,967,246
9	Energy Cost of Economy Purchases (Per E9)	$32,550	$30,450	$248,000	$712,800	$1,945,095	$3,360,000	$1,499,160	$2,135,900	$1,428,300	$923,800	$113,400	$33,480	$12,462,935
10	SolarTogether (ST) Credit	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$31,975,895
11	Total Fuel Costs & Net Power Transactions	$194,364,744	$184,396,107	$198,573,543	$198,229,134	$225,330,785	$237,079,808	$253,516,500	$260,196,400	$238,257,345	$234,944,903	$202,267,080	$208,882,274	$2,636,038,622
12														
13	Incremental Personnel, Software, and Hardware Costs	$42,507	$38,797	$41,981	$40,389	$43,573	$35,498	$37,090	$38,683	$33,906	$38,683	$37,090	$35,498	$463,695
14	Variable Power Plant O&M Attributable to Off-System Sales (Per E6)	$294,996	$237,887	$194,851	$113,100	$95,108	$68,640	$69,719	$54,405	$58,500	$59,241	$125,775	$182,962	$1,555,184
15	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	($1,008)	($943)	($8,060)	($21,060)	($53,801)	($87,360)	($37,479)	($53,398)	($40,365)	($30,024)	($4,095)	($1,209)	($338,800)
16	Total	$336,495	$275,741	$228,772	$132,429	$84,881	$16,778	$69,330	$39,690	$52,041	$67,900	$158,770	$217,251	$1,680,079
17														
18	Other O&M Expense	$28,874	$28,874	$28,874	$30,475	$228,595	$28,874	$173,246	$21,672					$569,484
19														
20	ADJUSTED TOTAL FUEL & NET POWER TRANS	$194,730,113	$184,700,722	$198,831,189	$198,392,038	$225,644,260	$237,125,460	$253,759,076	$260,257,763	$238,309,386	$235,012,803	$202,425,850	$209,099,525	$2,638,288,185
21														
22	System MWH Sales (Excluding Stratified Sales)	8,758,172	7,875,532	8,231,595	8,757,875	9,575,614	10,630,500	11,405,925	11,444,914	11,138,686	10,394,006	8,955,915	8,523,302	115,692,035
23														
24	Cost per KWh	2.2234	2.3452	2.4155	2.2653	2.3564	2.2306	2.2248	2.2740	2.1395	2.2610	2.2602	2.4533	2.2804
25	Jurisdictional Loss Multiplier	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132
26	Jurisdictional Cost	2.2263	2.3483	2.4187	2.2683	2.3596	2.2336	2.2277	2.2770	2.1423	2.2640	2.2632	2.4565	2.2835
27	True Up (cents/KWh)	(.0574)	(.0646)	(.0614)	(.0577)	(.0527)	(.0474)	(.0443)	(.0443)	(.0454)	(.0486)	(.0567)	(.0592)	(.0524)
28	Total (cents/KWh)	2.1689	2.2837	2.3573	2.2106	2.3069	2.1862	2.1834	2.2327	2.0969	2.2154	2.2065	2.3973	2.2311
29	Revenue Tax Factor	.0016	.0016	.0017	.0016	.0017	.0016	.0016	.0016	.0015	.0016	.0016	.0017	.0016
30	Recovery Factor adjusted for Taxes (cents/KWh)	2.1705	2.2853	2.3590	2.2122	2.3086	2.1878	2.1850	2.2343	2.0984	2.2170	2.2081	2.3990	2.2327
31	GPIF (cents/KWh)	.0085	.0095	.0091	.0085	.0078	.0070	.0065	.0065	.0067	.0072	.0084	.0087	.0077
32	Jurisdictional Incentive Mechanism - FPL Portion	.0126	.0142	.0135	.0127	.0116	.0104	.0097	.0097	.0100	.0107	.0125	.0130	.0115
33	Juridictionalized Savings Cents/KWH	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Recovery Factor Including GPIF and Incentive	2.1916	2.3090	2.3816	2.2334	2.3280	2.2052	2.2012	2.2505	2.1151	2.2349	2.2290	2.4207	2.2519
35														
36	Recovery Factor Rounded to .001 (¢/KWh)	2.192	2.309	2.382	2.233	2.328	2.205	2.201	2.251	2.115	2.235	2.229	2.421	2.252
37														

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

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1														
2	**Fuel Cost of System Net Generation ($)**													
3	Heavy Oil								478,463	432,310				910,773
4	Light Oil					2,951		3,859			178			6,988
5	Coal	5,234,753	4,997,950		1,761,089	5,317,088	5,187,421	5,595,227	5,667,262	5,362,555	5,539,209	5,237,142	5,343,980	55,243,676
6	Gas	182,279,507	173,363,235	189,539,454	187,048,319	204,310,674	215,156,770	233,553,886	238,082,034	218,018,237	217,313,972	185,941,139	192,416,202	2,437,023,429
7	Nuclear	13,804,272	11,576,132	11,727,933	9,619,400	12,894,130	12,478,191	12,894,130	12,894,130	12,478,191	10,034,574	11,521,600	13,659,338	145,582,023
8	**Total Fuel Cost of System Net Generation ($)**	201,318,532	189,937,316	201,267,387	198,428,808	222,524,843	232,822,382	252,047,102	257,121,888	236,291,294	232,887,934	202,699,881	211,419,521	2,638,766,889
9														
10	**System Net Generation (MWh)**													
11	Heavy Oil								3,578	3,252				6,831
12	Light Oil					17		22			1			41
13	Coal	181,095	172,978		60,503	183,652	179,304	194,057	196,002	184,272	189,929	178,686	181,390	1,901,868
14	Gas	6,208,146	5,933,563	6,790,722	7,201,606	7,554,641	8,274,703	9,011,605	9,056,868	8,273,464	7,967,437	6,236,199	6,089,005	88,597,958
15	Nuclear	2,589,680	2,161,201	2,227,752	1,913,441	2,523,667	2,442,258	2,523,667	2,523,667	2,442,258	2,004,960	2,256,134	2,604,188	28,212,873
16	Solar	199,686	280,328	342,208	356,895	448,252	381,560	406,656	391,752	362,262	369,496	325,684	295,473	4,160,252
17	**Total System Net Generation (MWh)**	9,178,607	8,548,070	9,360,682	9,532,445	10,710,229	11,277,825	12,136,007	12,171,867	11,265,508	10,531,823	8,996,703	9,170,056	122,879,823
18														
19	**Units of Fuel Burned (Unit)** [(a)]													
20	Heavy Oil								6,507	5,879				12,386
21	Light Oil					31		41			2			74
22	Coal	121,903	116,042		40,883	123,541	120,452	129,536	130,698	123,359	127,167	119,925	122,051	1,275,556
23	Gas	41,565,121	39,918,693	46,229,255	48,818,753	51,516,866	55,989,910	61,501,591	62,040,568	56,274,550	54,224,009	41,875,212	40,946,047	600,900,575
24	Nuclear	27,049,969	22,623,611	23,326,272	20,453,677	27,046,896	26,174,415	27,046,896	27,046,896	26,174,415	21,326,067	23,422,888	27,049,992	298,741,994
25														
26	**BTU Burned (MMBTU)**													
27	Heavy Oil								41,644	37,627				79,271
28	Light Oil					182		238			11			431
29	Coal	2,072,358	1,972,709		695,018	2,100,191	2,047,679	2,202,108	2,221,874	2,097,104	2,161,833	2,038,722	2,074,863	21,684,459
30	Gas	41,565,121	39,918,693	46,229,255	48,818,753	51,516,866	55,989,910	61,501,591	62,040,568	56,274,550	54,224,009	41,875,212	40,946,047	600,900,575
31	Nuclear	27,049,969	22,623,611	23,326,272	20,453,677	27,046,896	26,174,415	27,046,896	27,046,896	26,174,415	21,326,067	23,422,888	27,049,992	298,741,994
32	**Total BTU Burned (MMBTU)**	70,687,448	64,515,013	69,555,527	69,967,448	80,664,135	84,212,004	90,750,833	91,350,982	84,583,696	77,711,920	67,336,822	70,070,902	921,406,730
33														
34	**Fuel Cost per Unit ($/Unit)**													
35	Heavy Oil								73.5319	73.5319				73.5319
36	Light Oil					94.5239		94.5239			94.5239			94.5239
37	Coal	42.9418	43.0703		43.0759	43.0392	43.0664	43.1945	43.3613	43.4711	43.5587	43.6702	43.7849	43.3095
38	Gas	4.3854	4.3429	4.1000	3.8315	3.9659	3.8428	3.7975	3.8375	3.8742	4.0077	4.4404	4.6993	4.0556
39	Nuclear	0.5103	0.5117	0.5028	0.4703	0.4767	0.4767	0.4767	0.4767	0.4767	0.4705	0.4919	0.5050	0.4873
40														

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

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1	**Generation Mix (%)**													
2	Heavy Oil								0.03%	0.03%				0.01%
3	Light Oil					0.00%		0.00%			0.00%			0.00%
4	Coal	1.97%	2.02%		0.63%	1.71%	1.59%	1.60%	1.61%	1.64%	1.80%	1.99%	1.98%	1.55%
5	Gas	67.64%	69.41%	72.55%	75.55%	70.54%	73.37%	74.26%	74.41%	73.44%	75.65%	69.32%	66.40%	72.10%
6	Nuclear	28.21%	25.28%	23.80%	20.07%	23.56%	21.66%	20.79%	20.73%	21.68%	19.04%	25.08%	28.40%	22.96%
7	Solar	2.18%	3.28%	3.66%	3.74%	4.19%	3.38%	3.35%	3.22%	3.22%	3.51%	3.62%	3.22%	3.39%
8														
9	**Fuel Cost per MMBTU ($/MMBTU)**													
10	Heavy Oil								11.4894	11.4894				11.4894
11	Light Oil					16.2134		16.2134			16.2134			16.2134
12	Coal	2.5260	2.5335	0	2.5339	2.5317	2.5333	2.5409	2.5507	2.5571	2.5623	2.5688	2.5756	2.5476
13	Gas	4.3854	4.3429	4.1000	3.8315	3.9659	3.8428	3.7975	3.8375	3.8742	4.0077	4.4404	4.6993	4.0556
14	Nuclear	0.5103	0.5117	0.5028	0.4703	0.4767	0.4767	0.4767	0.4767	0.4767	0.4705	0.4919	0.5050	0.4873
15														
16	**BTU Burned per KWH (BTU/KWH)**													
17	Heavy Oil								11,638	11,569				11,605
18	Light Oil					10,577		10,604			10,568			10,591
19	Coal	11,443	11,404		11,487	11,436	11,420	11,348	11,336	11,380	11,382	11,410	11,439	11,402
20	Gas	6,695	6,728	6,808	6,779	6,819	6,766	6,825	6,850	6,802	6,806	6,715	6,725	6,782
21	Nuclear	10,445	10,468	10,471	10,689	10,717	10,717	10,717	10,717	10,717	10,637	10,382	10,387	10,589
22														
23	**Generated Fuel Cost per KWH (cents/KWH)**													
24	Heavy Oil	0	0	0	0	0	0	0	13.3715	13.2922	0	0	0	13.3338
25	Light Oil					17.1485		17.1920			17.1351			17.1722
26	Coal	2.8906	2.8894		2.9107	2.8952	2.8931	2.8833	2.8914	2.9101	2.9165	2.9309	2.9461	2.9047
27	Gas	2.9361	2.9217	2.7912	2.5973	2.7044	2.6002	2.5917	2.6287	2.6352	2.7275	2.9816	3.1601	2.7507
28	Nuclear	0.5330	0.5356	0.5264	0.5027	0.5109	0.5109	0.5109	0.5109	0.5109	0.5005	0.5107	0.5245	0.5160
29	**Total Generated Fuel Cost per KWH (cents/KWH)**	2.1933	2.2220	2.1501	2.0816	2.0777	2.0644	2.0769	2.1124	2.0975	2.2113	2.2530	2.3055	2.1474
30														
31														
32														
33														
34														
35														
36														
37														
38	[(a)] Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER													
39														
40	Note: Totals may not add due to rounding.													

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		12,457				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,457	22.5%	N/A	44.9%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		12,650				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,650	22.8%	N/A	49.8%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		12,504				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,504	22.6%	N/A	49.2%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		650,858				6,686	4,351,712	1,000,000	4,351,712	19,104,846	2.94	4.39
14	Plant Unit Info	1,307.0	650,858	66.9%	93.9%	66.9%	6,686			4,351,712	19,104,846	2.94	
15	Citrus PV Solar												
16	Solar		12,537				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	12,537	22.6%	N/A	49.4%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		12,288				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	12,288	22.2%	N/A	48.4%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		3,151				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	3,151	16.9%	N/A	37.0%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		582,146				7,353	4,280,241	1,000,000	4,280,241	18,791,424	3.23	4.39
26	Plant Unit Info	1,791.0	582,146	43.7%	94.0%	43.7%	7,353			4,280,241	18,791,424	3.23	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	195.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	195.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00
38	Plant Unit Info	213.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		0					0	0	0	0	0.00	0.00
42	Plant Unit Info	213.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
43	Echo River PV Solar												
44	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		12,959				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	12,959	23.4%	N/A	51.0%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		12,391				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	12,391	22.4%	N/A	48.8%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		12,466				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	12,466	22.5%	N/A	49.1%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0					0	0	0	0	0.00	
60	Plant Unit Info	0.0	0	0.0%	N/A	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		12,666				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	12,666	22.9%	N/A	49.9%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		0					0	0	0	0	0.00	0.00
7	Plant Unit Info	213.0	0	0.0%	71.4%	0.0%	0			0	0	0.00	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	213.0	0	0.0%	71.4%	0.0%	0			0	0	0.00	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	213.0	0	0.0%	71.4%	0.0%	0			0	0	0.00	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	213.0	0	0.0%	87.5%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	213.0	0	0.0%	87.5%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		12,601				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,601	22.7%	N/A	49.6%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	795.0	0	0.0%	51.0%	0.0%	0			0	0	0.00	
31	Manatee 2												
32	Heavy Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	795.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
35	Manatee 3												
36	Gas		123,563				8,168	1,009,252	1,000,000	1,009,252	4,406,195	3.57	4.37
37	Plant Unit Info	1,251.0	123,563	13.3%	94.1%	54.6%	8,168			1,009,252	4,406,195	3.57	
38	Manatee PV Solar												
39	Solar		12,567				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	12,567	22.7%	N/A	45.3%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		1,342				12,321	16,535	1,000,000	16,535	72,214	5.38	4.37
43	Plant Unit Info	489.0	1,342	0.4%	93.9%	55.1%	12,321			16,535	72,214	5.38	
44	Martin 4												
45	Gas		2,978				11,693	34,823	1,000,000	34,823	152,128	5.11	4.37
46	Plant Unit Info	489.0	2,978	0.8%	94.0%	50.8%	11,693			34,823	152,128	5.11	
47	Martin 8 Solar												
48	Solar		7,409				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	7,409	13.3%	N/A	29.0%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		74,406				8,365	622,421	1,000,000	622,421	2,718,278	3.65	4.37
53	Plant Unit Info	1,246.0	74,406	8.0%	94.0%	62.9%	8,365			622,421	2,718,278	3.65	
54	Miami-Dade PV Solar												
55	Solar		13,155				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	13,155	23.7%	N/A	51.8%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,067,145				6,129	6,540,082	1,000,000	6,540,082	28,882,522	2.71	4.42
60	Plant Unit Info	1,638.0	1,067,145	87.6%	96.7%	87.6%	6,129			6,540,082	28,882,522	2.71	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		860,368				6,335	5,450,736	1,000,000	5,450,736	23,930,174	2.78	4.39
7	Plant Unit Info	1,251.0	860,368	92.4%	93.9%	92.4%	6,335			5,450,736	23,930,174	2.78	
8	Pioneer Trail PV Solar												
9	Solar		12,109				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,109	21.9%	N/A	47.7%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0							0	0	0.00	0.00
13	Gas		657,885				6,686	4,398,495	1,000,000	4,398,495	19,310,924	2.94	4.39
14	Plant Unit Info	1,307.0	657,885	67.7%	93.9%	67.7%	6,686			4,398,495	19,310,924	2.94	
15	Sanford 4												
16	Gas		18,630				8,197	152,704	1,000,000	152,704	670,464	3.60	4.39
17	Plant Unit Info	1,088.0	18,630	2.3%	94.0%	51.9%	8,197			152,704	670,464	3.60	
18	Sanford 5												
19	Gas		35,273				8,286	292,261	1,000,000	292,261	1,283,204	3.64	4.39
20	Plant Unit Info	1,180.0	35,273	4.0%	74.6%	48.2%	8,286			292,261	1,283,204	3.64	
21	Scherer 4												
22	Coal		181,095				11,443	121,903	17,000,000	2,072,358	5,234,753	2.89	42.94
23	Plant Unit Info	626.0	181,095	38.9%	94.8%	38.9%	11,443			2,072,358	5,234,753	2.89	
24	Southfork PV Solar												
25	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,280				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,280	17.2%	N/A	37.5%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		728,079				10,328	7,519,590	1,000,000	7,519,590	3,521,447	0.48	0.47
32	Plant Unit Info	1,003.0	728,079	97.5%	97.5%	97.5%	10,328			7,519,590	3,521,447	0.48	
33	St Lucie 2												
34	Nuclear		623,343				10,257	6,393,629	1,000,000	6,393,629	3,189,525	0.51	0.50
35	Plant Unit Info	860.0	623,343	97.5%	97.5%	97.5%	10,257			6,393,629	3,189,525	0.51	
36	ST Project 1 Site 1												
37	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		11,773				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	11,773	21.1%	N/A	46.0%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		623,119				10,541	6,568,293	1,000,000	6,568,293	3,810,057	0.61	0.58
59	Plant Unit Info	859.0	623,119	97.5%	97.5%	97.5%	10,541			6,568,293	3,810,057	0.61	
60	Turkey Point 4												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		615,139				10,678	6,568,457	1,000,000	6,568,457	3,283,243	0.53	0.50
2	Plant Unit Info	848.0	615,139	97.5%	97.5%	97.5%	10,678			6,568,457	3,283,243	0.53	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		95,563				8,484	810,794	1,000,000	810,794	3,559,172	3.72	4.39
6	Plant Unit Info	1,264.0	95,563	10.2%	94.0%	47.5%	8,484			810,794	3,559,172	3.72	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		647,898				6,660	4,315,221	1,000,000	4,315,221	18,839,598	2.91	4.37
10	Plant Unit Info	1,267.0	647,898	68.7%	93.9%	68.7%	6,660			4,315,221	18,839,598	2.91	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		742,291				6,637	4,926,442	1,000,000	4,926,442	21,508,394	2.90	4.37
14	Plant Unit Info	1,267.0	742,291	78.8%	93.9%	78.8%	6,637			4,926,442	21,508,394	2.90	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		647,800				6,736	4,363,402	1,000,000	4,363,402	19,049,970	2.94	4.37
18	Plant Unit Info	1,242.0	647,800	70.1%	93.9%	70.1%	6,736			4,363,402	19,049,970	2.94	
19	Wildflower PV Solar												
20	Solar		12,723				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	12,723	23.0%	N/A	50.1%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,793	9,178,607				7,701			70,687,448	201,318,532	2.19	
24													
25													
26													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		12,967				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,967	25.0%	N/A	50.0%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		13,114				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,114	25.3%	N/A	55.2%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		13,054				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,054	25.2%	N/A	54.9%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		473,390				6,691	3,167,453	1,000,000	3,167,453	13,771,323	2.91	4.35
14	Plant Unit Info	1,307.0	473,390	52.0%	70.9%	53.9%	6,691			3,167,453	13,771,323	2.91	
15	Citrus PV Solar												
16	Solar		12,701				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	12,701	24.5%	N/A	49.0%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		12,536				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	12,536	24.2%	N/A	48.4%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		3,355				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	3,355	19.3%	N/A	38.6%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		432,529				7,324	3,167,654	1,000,000	3,167,654	13,765,181	3.18	4.35
26	Plant Unit Info	1,791.0	432,529	34.7%	61.8%	45.7%	7,324			3,167,654	13,765,181	3.18	
27	Fort Myers 3A												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		0				0	0	0	0	0	0.00	0.00
30	Plant Unit Info	195.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0				0	0	0	0	0	0.00	0.00
33	Gas		0				0	0	0	0	0	0.00	0.00
34	Plant Unit Info	195.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		887				11,230	9,961	1,000,000	9,961	43,308	4.88	4.35
38	Plant Unit Info	213.0	887	0.6%	93.5%	83.5%	11,230			9,961	43,308	4.88	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		887				11,230	9,961	1,000,000	9,961	43,308	4.88	4.35
42	Plant Unit Info	213.0	887	0.6%	93.5%	83.5%	11,230			9,961	43,308	4.88	
43	Echo River PV Solar												
44	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		13,632				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	13,632	26.3%	N/A	52.6%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		12,632				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	12,632	24.4%	N/A	48.7%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		13,012				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	13,012	25.1%	N/A	54.7%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0				0	0	0	0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	0	0	0	0	0	0.00	

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		13,272				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	13,272	25.6%	N/A	55.9%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		2,002				10,634	21,289	1,000,000	21,289	92,561	4.62	4.35
7	Plant Unit Info	213.0	2,002	1.4%	94.0%	94.0%	10,634			21,289	92,561	4.62	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		2,002				10,634	21,289	1,000,000	21,289	92,561	4.62	4.35
11	Plant Unit Info	213.0	2,002	1.4%	94.0%	94.0%	10,634			21,289	92,561	4.62	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		2,002				10,634	21,289	1,000,000	21,289	92,561	4.62	4.35
15	Plant Unit Info	213.0	2,002	1.4%	94.0%	94.0%	10,634			21,289	92,561	4.62	
16	Lauderdale 6D												
17	Light Oil		0				0	0	0	0	0	0.00	0.00
18	Gas		0				0	0	0	0	0	0.00	0.00
19	Plant Unit Info	213.0	0	0.0%	76.8%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0				0	0	0	0	0	0.00	0.00
22	Gas		0				0	0	0	0	0	0.00	0.00
23	Plant Unit Info	213.0	0	0.0%	76.8%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		13,252				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,252	25.6%	N/A	55.8%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		0				0	0	0	0	0	0.00	0.00
30	Plant Unit Info	795.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
31	Manatee 2												
32	Heavy Oil		0				0	0	0	0	0	0.00	0.00
33	Gas		0				0	0	0	0	0	0.00	0.00
34	Plant Unit Info	795.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
35	Manatee 3												
36	Gas		198,052				7,834	1,551,565	1,000,000	1,551,565	6,704,160	3.39	4.32
37	Plant Unit Info	1,251.0	198,052	22.8%	94.1%	64.9%	7,834			1,551,565	6,704,160	3.39	
38	Manatee PV Solar												
39	Solar		12,621				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	12,621	24.3%	N/A	48.7%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		12,362				8,868	109,630	1,000,000	109,630	474,471	3.84	4.33
43	Plant Unit Info	489.0	12,362	3.6%	93.9%	45.9%	8,868			109,630	474,471	3.84	
44	Martin 4												
45	Gas		22,782				8,715	198,537	1,000,000	198,537	858,969	3.77	4.33
46	Plant Unit Info	489.0	22,782	6.7%	94.0%	71.6%	8,715			198,537	858,969	3.77	
47	Martin 8 Solar												
48	Solar		6,363				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	6,363	12.2%	N/A	33.7%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		38,259				8,002	306,138	1,000,000	306,138	1,324,559	3.46	4.33
53	Plant Unit Info	1,246.0	38,259	4.4%	66.4%	60.2%	8,002			306,138	1,324,559	3.46	
54	Miami-Dade PV Solar												
55	Solar		13,626				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	13,626	26.3%	N/A	57.3%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		999,608				6,131	6,128,827	1,000,000	6,128,827	26,870,875	2.69	4.38
60	Plant Unit Info	1,638.0	999,608	87.7%	96.7%	87.7%	6,131			6,128,827	26,870,875	2.69	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		804,122				6,336	5,094,946	1,000,000	5,094,946	22,143,224	2.75	4.35
7	Plant Unit Info	1,251.0	804,122	92.4%	93.9%	92.4%	6,336			5,094,946	22,143,224	2.75	
8	Pioneer Trail PV Solar												
9	Solar		12,344				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,344	23.8%	N/A	51.9%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		621,302				6,665	4,140,826	1,000,000	4,140,826	18,000,111	2.90	4.35
14	Plant Unit Info	1,307.0	621,302	68.3%	93.9%	68.3%	6,665			4,140,826	18,000,111	2.90	
15	Sanford 4												
16	Gas		89,214				7,832	698,732	1,000,000	698,732	3,037,920	3.41	4.35
17	Plant Unit Info	1,088.0	89,214	11.8%	94.0%	64.1%	7,832			698,732	3,037,920	3.41	
18	Sanford 5												
19	Gas		95,385				7,885	752,125	1,000,000	752,125	3,270,058	3.43	4.35
20	Plant Unit Info	1,180.0	95,385	11.6%	90.6%	61.2%	7,885			752,125	3,270,058	3.43	
21	Scherer 4												
22	Coal		172,978				11,404	116,042	17,000,000	1,972,709	4,997,950	2.89	43.07
23	Plant Unit Info	626.0	172,978	39.7%	94.8%	39.7%	11,404			1,972,709	4,997,950	2.89	
24	Southfork PV Solar												
25	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,319				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,319	19.0%	N/A	37.9%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		681,105				10,328	7,034,456	1,000,000	7,034,456	3,294,257	0.48	0.47
32	Plant Unit Info	1,003.0	681,105	97.5%	97.5%	97.5%	10,328			7,034,456	3,294,257	0.48	
33	St Lucie 2												
34	Nuclear		321,726				10,257	3,299,937	1,000,000	3,299,937	1,646,207	0.51	0.50
35	Plant Unit Info	860.0	321,726	53.8%	53.8%	97.5%	10,257			3,299,937	1,646,207	0.51	
36	ST Project 1 Site 1												
37	Solar		12,550				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	12,550	24.2%	N/A	52.8%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		12,181				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	12,181	23.5%	N/A	47.0%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		12,781				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	12,781	24.7%	N/A	49.3%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		12,437				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	12,437	24.0%	N/A	48.0%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		12,646				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	12,646	24.4%	N/A	48.8%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		12,633				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	12,633	24.4%	N/A	48.7%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		12,243				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	12,243	23.5%	N/A	46.9%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		582,917				10,541	6,144,533	1,000,000	6,144,533	3,564,247	0.61	0.58
59	Plant Unit Info	859.0	582,917	97.5%	97.5%	97.5%	10,541			6,144,533	3,564,247	0.61	
60	Turkey Point 4												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		575,453				10,678	6,144,685	1,000,000	6,144,685	3,071,421	0.53	0.50
2	Plant Unit Info	848.0	575,453	97.5%	97.5%	97.5%	10,678			6,144,685	3,071,421	0.53	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		195,926				7,963	1,560,182	1,000,000	1,560,182	6,779,770	3.46	4.35
6	Plant Unit Info	1,264.0	195,926	22.3%	94.0%	59.6%	7,963			1,560,182	6,779,770	3.46	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		614,622				6,650	4,087,029	1,000,000	4,087,029	17,661,234	2.87	4.32
10	Plant Unit Info	1,267.0	614,622	69.7%	93.9%	69.7%	6,650			4,087,029	17,661,234	2.87	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		691,472				6,639	4,590,398	1,000,000	4,590,398	19,837,529	2.87	4.32
14	Plant Unit Info	1,267.0	691,472	78.4%	93.9%	78.4%	6,639			4,590,398	19,837,529	2.87	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		636,758				6,723	4,280,862	1,000,000	4,280,862	18,499,554	2.91	4.32
18	Plant Unit Info	1,242.0	636,758	73.7%	93.9%	73.7%	6,723			4,280,862	18,499,554	2.91	
19	Wildflower PV Solar												
20	Solar		13,057				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,057	25.2%	N/A	50.4%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,793	8,548,070				7,547			64,515,013	189,937,316	2.22	
24													
25													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		15,355				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	15,355	27.7%	N/A	51.1%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		16,016				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	16,016	28.9%	N/A	53.3%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		15,728				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,728	28.4%	N/A	52.4%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		81,003				6,771	548,489	1,000,000	548,489	2,237,542	2.76	4.08
14	Plant Unit Info	1,307.0	81,003	6.8%	6.8%	64.6%	6,771			548,489	2,237,542	2.76	
15	Citrus PV Solar												
16	Solar		15,250				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	15,250	27.5%	N/A	50.8%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		15,514				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	15,514	28.0%	N/A	51.7%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		4,460				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	4,460	24.0%	N/A	44.3%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		716,748				7,297	5,230,211	1,000,000	5,230,211	21,501,730	3.00	4.11
26	Plant Unit Info	1,791.0	716,748	53.8%	94.0%	53.8%	7,297			5,230,211	21,501,730	3.00	
27	Fort Myers 3A												
28	Light Oil		0				0	0	0	0	0	0.00	0.00
29	Gas		0				0	0	0	0	0	0.00	0.00
30	Plant Unit Info	195.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0				0	0	0	0	0	0.00	0.00
33	Gas		0				0	0	0	0	0	0.00	0.00
34	Plant Unit Info	195.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		3,874				10,787	41,787	1,000,000	41,787	171,900	4.44	4.11
38	Plant Unit Info	213.0	3,874	2.4%	93.5%	90.8%	10,787			41,787	171,900	4.44	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		4,776				10,854	51,840	1,000,000	51,840	213,256	4.47	4.11
42	Plant Unit Info	213.0	4,776	3.0%	93.5%	89.6%	10,854			51,840	213,256	4.47	
43	Echo River PV Solar												
44	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		16,191				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	16,191	29.2%	N/A	53.9%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		15,564				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	15,564	28.1%	N/A	51.8%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		15,679				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	15,679	28.3%	N/A	52.2%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0							0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		15,901				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	15,901	28.7%	N/A	53.0%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		8,810				10,605	93,434	1,000,000	93,434	384,362	4.36	4.11
7	Plant Unit Info	213.0	8,810	5.6%	94.0%	94.0%	10,605			93,434	384,362	4.36	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		6,007				10,632	63,868	1,000,000	63,868	262,738	4.37	4.11
11	Plant Unit Info	213.0	6,007	3.8%	94.0%	94.0%	10,632			63,868	262,738	4.37	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		7,809				10,602	82,789	1,000,000	82,789	340,573	4.36	4.11
15	Plant Unit Info	213.0	7,809	4.9%	94.0%	94.0%	10,602			82,789	340,573	4.36	
16	Lauderdale 6D												
17	Light Oil		0				0	0	0	0	0	0.00	0.00
18	Gas		0				0	0	0	0	0	0.00	0.00
19	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0				0	0	0	0	0	0.00	0.00
22	Gas		0				0	0	0	0	0	0.00	0.00
23	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		15,924				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,924	28.7%	N/A	53.0%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		5,725				15,124	86,583	1,000,000	86,583	354,265	6.19	4.09
30	Plant Unit Info	795.0	5,725	1.0%	96.2%	30.1%	15,124			86,583	354,265	6.19	
31	Manatee 2												
32	Heavy Oil		0					0	0	0	0	0.00	0.00
33	Gas		2,981				14,871	44,331	1,000,000	44,331	181,425	6.09	4.09
34	Plant Unit Info	795.0	2,981	0.5%	83.3%	31.0%	14,871			44,331	181,425	6.09	
35	Manatee 3												
36	Gas		411,163				7,366	3,028,524	1,000,000	3,028,524	12,379,457	3.01	4.09
37	Plant Unit Info	1,251.0	411,163	44.2%	94.1%	61.9%	7,366			3,028,524	12,379,457	3.01	
38	Manatee PV Solar												
39	Solar		15,386				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	15,386	27.8%	N/A	51.2%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		37,908				8,540	323,753	1,000,000	323,753	1,325,674	3.50	4.09
43	Plant Unit Info	489.0	37,908	10.4%	93.9%	57.4%	8,540			323,753	1,325,674	3.50	
44	Martin 4												
45	Gas		50,560				8,855	447,707	1,000,000	447,707	1,834,379	3.63	4.10
46	Plant Unit Info	489.0	50,560	13.9%	94.0%	74.4%	8,855			447,707	1,834,379	3.63	
47	Martin 8 Solar												
48	Solar		8,426				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	8,426	15.1%	N/A	39.3%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		240,392				7,560	1,817,386	1,000,000	1,817,386	7,441,200	3.10	4.09
53	Plant Unit Info	1,246.0	240,392	25.9%	65.0%	69.9%	7,560			1,817,386	7,441,200	3.10	
54	Miami-Dade PV Solar												
55	Solar		16,192				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	16,192	29.2%	N/A	53.9%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		611,629				6,139	3,754,643	1,000,000	3,754,643	15,462,409	2.53	4.12
60	Plant Unit Info	1,638.0	611,629	50.2%	51.5%	91.5%	6,139			3,754,643	15,462,409	2.53	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		868,887				6,329	5,499,106	1,000,000	5,499,106	22,604,683	2.60	4.11
7	Plant Unit Info	1,251.0	868,887	93.4%	93.9%	93.4%	6,329			5,499,106	22,604,683	2.60	
8	Pioneer Trail PV Solar												
9	Solar		15,297				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,297	27.6%	N/A	51.0%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		786,633				6,594	5,187,188	1,000,000	5,187,188	21,321,829	2.71	4.11
14	Plant Unit Info	1,307.0	786,633	80.9%	93.9%	80.9%	6,594			5,187,188	21,321,829	2.71	
15	Sanford 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	1,088.0	0	0.0%	N/A	0.0%	0			N/A	N/A	N/A	
18	Sanford 5												
19	Gas		288,380				7,317	2,110,197	1,000,000	2,110,197	8,680,806	3.01	4.11
20	Plant Unit Info	1,180.0	288,380	32.9%	94.0%	57.0%	7,317			2,110,197	8,680,806	3.01	
21	Scherer 4												
22	Coal		0										
23	Plant Unit Info	626.0	0	0.0%	N/A	0.0%	0			N/A	N/A	N/A	
24	Southfork PV Solar												
25	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,626				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,626	21.9%	N/A	40.3%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		728,079				10,328	7,519,590	1,000,000	7,519,590	3,521,447	0.48	0.47
32	Plant Unit Info	1,003.0	728,079	97.5%	97.5%	97.5%	10,328			7,519,590	3,521,447	0.48	
33	St Lucie 2												
34	Nuclear		301,618				10,257	3,093,691	1,000,000	3,093,691	1,358,997	0.45	0.44
35	Plant Unit Info	860.0	301,618	47.2%	47.2%	97.5%	10,257			3,093,691	1,358,997	0.45	
36	ST Project 1 Site 1												
37	Solar		15,004				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	15,004	27.1%	N/A	50.0%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		14,447				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	14,447	26.1%	N/A	48.1%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		16,816				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	16,816	30.3%	N/A	56.0%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		16,364				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	16,364	29.5%	N/A	54.5%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		14,999				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	14,999	27.1%	N/A	50.0%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		14,984				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	14,984	27.0%	N/A	49.9%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		15,293				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	15,293	27.4%	N/A	50.6%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		582,917				10,541	6,144,533	1,000,000	6,144,533	3,564,247	0.61	0.58
59	Plant Unit Info	859.0	582,917	91.2%	91.2%	97.5%	10,541			6,144,533	3,564,247	0.61	
60	Turkey Point 4												

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		615,139				10,678	6,568,457	1,000,000	6,568,457	3,283,243	0.53	0.50
2	Plant Unit Info	848.0	615,139	97.5%	97.5%	97.5%	10,678			6,568,457	3,283,243	0.53	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		333,121				7,374	2,456,400	1,000,000	2,456,400	10,096,638	3.03	4.11
6	Plant Unit Info	1,264.0	333,121	35.4%	94.0%	59.8%	7,374			2,456,400	10,096,638	3.03	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		731,216				6,555	4,792,982	1,000,000	4,792,982	19,581,014	2.68	4.09
10	Plant Unit Info	1,267.0	731,216	77.6%	81.0%	77.6%	6,555			4,792,982	19,581,014	2.68	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		824,388				6,565	5,412,425	1,000,000	5,412,425	22,106,811	2.68	4.08
14	Plant Unit Info	1,267.0	824,388	87.5%	93.9%	87.5%	6,565			5,412,425	22,106,811	2.68	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		768,712				6,707	5,155,612	1,000,000	5,155,612	21,056,763	2.74	4.08
18	Plant Unit Info	1,242.0	768,712	83.2%	93.9%	83.2%	6,707			5,155,612	21,056,763	2.74	
19	Wildflower PV Solar												
20	Solar		15,792				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	15,792	28.5%	N/A	52.6%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,793	9,360,682				7,431			69,555,527	201,267,387	2.15	
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
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Docket No. 20190001-EI
Appendix II - 2020 FCR Projections
Exhibit RBD-7, Page 28 of 79

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		15,726				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	15,726	29.3%	N/A	54.1%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		16,332				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	16,332	30.5%	N/A	56.2%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		15,916				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,916	29.7%	N/A	54.8%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		732,450				6,628	4,854,924	1,000,000	4,854,924	18,695,605	2.55	3.85
14	Plant Unit Info	1,309.0	732,450	77.7%	93.9%	77.7%	6,628			4,854,924	18,695,605	2.55	
15	Citrus PV Solar												
16	Solar		15,795				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	15,795	29.5%	N/A	54.4%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		16,323				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	16,323	30.4%	N/A	56.2%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		4,930				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	4,930	27.4%	N/A	50.6%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		692,437				7,277	5,039,144	1,000,000	5,039,144	19,403,663	2.80	3.85
26	Plant Unit Info	1,774.0	692,437	54.2%	94.0%	54.2%	7,277			5,039,144	19,403,663	2.80	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		1,005				10,558	10,611	1,000,000	10,611	40,853	4.06	3.85
38	Plant Unit Info	215.0	1,005	0.7%	93.5%	93.6%	10,558			10,611	40,853	4.06	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		1,005				10,558	10,611	1,000,000	10,611	40,853	4.06	3.85
42	Plant Unit Info	215.0	1,005	0.7%	93.5%	93.6%	10,558			10,611	40,853	4.06	
43	Echo River PV Solar												
44	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		16,172				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	16,172	30.2%	N/A	55.7%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		16,405				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	16,405	30.6%	N/A	56.5%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		15,864				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	15,864	29.6%	N/A	54.6%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0					0	0	0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		16,453				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	16,453	30.7%	N/A	56.6%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		3,032				10,536	31,945	1,000,000	31,945	122,990	4.06	3.85
7	Plant Unit Info	215.0	3,032	2.0%	94.0%	94.1%	10,536			31,945	122,990	4.06	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		3,746				10,667	39,960	1,000,000	39,960	153,848	4.11	3.85
11	Plant Unit Info	215.0	3,746	2.4%	94.0%	91.7%	10,667			39,960	153,848	4.11	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		2,021				10,538	21,297	1,000,000	21,297	81,994	4.06	3.85
15	Plant Unit Info	215.0	2,021	1.3%	94.0%	94.3%	10,538			21,297	81,994	4.06	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		15,936				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,936	29.7%	N/A	54.8%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	790.0	0	0.0%	92.9%	0.0%	0			0	0	0.00	
31	Manatee 2												
32	Heavy Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	790.0	0	0.0%	62.9%	0.0%	0			0	0	0.00	
35	Manatee 3												
36	Gas		413,099				7,318	3,023,089	1,000,000	3,023,089	11,480,246	2.78	3.80
37	Plant Unit Info	1,238.0	413,099	46.3%	94.1%	65.9%	7,318			3,023,089	11,480,246	2.78	
38	Manatee PV Solar												
39	Solar		15,985				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	15,985	29.8%	N/A	55.0%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		21,120				8,516	179,850	1,000,000	179,850	683,713	3.24	3.80
43	Plant Unit Info	476.0	21,120	6.2%	93.9%	62.5%	8,516			179,850	683,713	3.24	
44	Martin 4												
45	Gas		40,642				8,444	343,179	1,000,000	343,179	1,304,619	3.21	3.80
46	Plant Unit Info	476.0	40,642	11.9%	94.0%	59.3%	8,444			343,179	1,304,619	3.21	
47	Martin 8 Solar												
48	Solar		14,310				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	14,310	26.5%	N/A	48.9%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		347,967				7,636	2,657,021	1,000,000	2,657,021	10,098,843	2.90	3.80
53	Plant Unit Info	1,231.0	347,967	39.3%	94.0%	75.8%	7,636			2,657,021	10,098,843	2.90	
54	Miami-Dade PV Solar												
55	Solar		16,129				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	16,129	30.1%	N/A	55.5%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,084,111				6,177	6,696,837	1,000,000	6,696,837	25,889,110	2.39	3.87
60	Plant Unit Info	1,652.0	1,084,111	91.1%	96.7%	91.1%	6,177			6,696,837	25,889,110	2.39	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		597,370				6,396	3,821,009	1,000,000	3,821,009	14,715,317	2.46	3.85
7	Plant Unit Info	1,264.0	597,370	65.6%	72.2%	65.6%	6,396			3,821,009	14,715,317	2.46	
8	Pioneer Trail PV Solar												
9	Solar		16,101				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,101	30.0%	N/A	55.4%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		737,925				6,628	4,891,142	1,000,000	4,891,142	18,846,724	2.55	3.85
14	Plant Unit Info	1,309.0	737,925	78.3%	93.9%	78.3%	6,628			4,891,142	18,846,724	2.55	
15	Sanford 4												
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	1,164.0	0	0.0%	N/A	0.0%	0			0	0	0.00	
18	Sanford 5												
19	Gas		191,270				7,727	1,478,014	1,000,000	1,478,014	5,692,244	2.98	3.85
20	Plant Unit Info	1,164.0	191,270	22.8%	94.0%	62.5%	7,727			1,478,014	5,692,244	2.98	
21	Scherer 4												
22	Coal		60,503				11,487	40,883	17,000,000	695,018	1,761,089	2.91	43.08
23	Plant Unit Info	625.0	60,503	13.5%	28.1%	40.4%	11,487			695,018	1,761,089	2.91	
24	Southfork PV Solar												
25	Solar		0				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,682				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,682	23.4%	N/A	40.0%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		688,707				10,560	7,272,748	1,000,000	7,272,748	3,405,849	0.49	0.47
32	Plant Unit Info	981.0	688,707	97.5%	97.5%	97.5%	10,560			7,272,748	3,405,849	0.49	
33	St Lucie 2												
34	Nuclear		589,635				10,496	6,188,815	1,000,000	6,188,815	2,718,623	0.46	0.44
35	Plant Unit Info	840.0	589,635	97.5%	97.5%	97.5%	10,496			6,188,815	2,718,623	0.46	
36	ST Project 1 Site 1												
37	Solar		14,791				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	14,791	27.6%	N/A	50.9%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		14,395				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	14,395	26.8%	N/A	49.6%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		17,972				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	17,972	33.5%	N/A	61.9%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		17,489				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	17,489	32.6%	N/A	60.2%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		14,945				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	14,945	27.9%	N/A	51.4%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		14,930				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	14,930	27.8%	N/A	51.4%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		16,131				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	16,131	29.9%	N/A	55.1%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		58,757				10,818	635,638	1,000,000	635,638	317,643	0.54	0.50
59	Plant Unit Info	837.0	58,757	9.8%	9.7%	97.5%	10,818			635,638	317,643	0.54	
60	Turkey Point 4												

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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		576,342				11,029	6,356,476	1,000,000	6,356,476	3,177,285	0.55	0.50
2	Plant Unit Info	821.0	576,342	97.5%	97.5%	97.5%	11,029			6,356,476	3,177,285	0.55	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		307,975				7,611	2,343,876	1,000,000	2,343,876	9,025,027	2.93	3.85
6	Plant Unit Info	1,248.0	307,975	34.3%	94.0%	65.8%	7,611			2,343,876	9,025,027	2.93	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		721,607				6,586	4,752,161	1,000,000	4,752,161	18,037,993	2.50	3.80
10	Plant Unit Info	1,264.0	721,607	79.3%	85.0%	79.3%	6,586			4,752,161	18,037,993	2.50	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		498,262				6,634	3,305,428	1,000,000	3,305,428	12,546,315	2.52	3.80
14	Plant Unit Info	1,264.0	498,262	54.8%	58.3%	65.7%	6,634			3,305,428	12,546,315	2.52	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		804,562				6,611	5,318,655	1,000,000	5,318,655	20,188,361	2.51	3.80
18	Plant Unit Info	1,247.0	804,562	89.6%	93.9%	89.6%	6,611			5,318,655	20,188,361	2.51	
19	Wildflower PV Solar												
20	Solar		16,183				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	16,183	30.2%	N/A	55.7%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,674	9,532,445				7,340			69,967,448	198,428,808	2.08	
24													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		16,053				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	16,053	29.0%	N/A	46.3%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		16,838				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	16,838	30.4%	N/A	56.1%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		16,431				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,431	29.6%	N/A	54.7%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		746,151				6,619	4,938,516	1,000,000	4,938,516	19,687,428	2.64	3.99
14	Plant Unit Info	1,309.0	746,151	76.6%	93.9%	76.6%	6,619			4,938,516	19,687,428	2.64	
15	Citrus PV Solar												
16	Solar		16,285				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	16,285	29.4%	N/A	47.0%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		17,413				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	17,413	31.4%	N/A	58.0%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		5,080				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	5,080	27.3%	N/A	43.7%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		743,062				7,275	5,405,418	1,000,000	5,405,418	21,547,606	2.90	3.99
26	Plant Unit Info	1,774.0	743,062	56.3%	94.0%	56.3%	7,275			5,405,418	21,547,606	2.90	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		17				10,577	31	5,830,000	182	2,951	17.15	94.52
37	Gas		2,797				10,577	29,581	1,000,000	29,581	117,896	4.22	3.99
38	Plant Unit Info	215.0	2,814	1.8%	93.5%	93.5%	10,577			29,763	120,846	4.29	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		1,809				10,591	19,160	1,000,000	19,160	76,362	4.22	3.99
42	Plant Unit Info	215.0	1,809	1.1%	93.5%	93.4%	10,591			19,160	76,362	4.22	
43	Echo River PV Solar												
44	Solar		21,384				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	21,384	38.6%	N/A	61.7%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		16,626				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	16,626	30.0%	N/A	55.4%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		17,041				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	17,041	30.8%	N/A	56.8%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		17,580				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	17,580	31.7%	N/A	58.6%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		16,378				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	16,378	29.6%	N/A	54.6%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0					0	0	0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		16,888				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	16,888	30.5%	N/A	56.3%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		4,648				10,564	49,102	1,000,000	49,102	195,698	4.21	3.99
7	Plant Unit Info	215.0	4,648	2.9%	94.0%	94.1%	10,564			49,102	195,698	4.21	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		4,648				10,564	49,102	1,000,000	49,102	195,698	4.21	3.99
11	Plant Unit Info	215.0	4,648	2.9%	94.0%	94.1%	10,564			49,102	195,698	4.21	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		6,063				10,538	63,890	1,000,000	63,890	254,635	4.20	3.99
15	Plant Unit Info	215.0	6,063	3.8%	94.0%	94.0%	10,538			63,890	254,635	4.20	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		16,390				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	16,390	29.6%	N/A	54.6%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	790.0	0	0.0%	67.2%	0.0%	0			0	0	0.00	
31	Manatee 2												
32	Heavy Oil		0					0	0	0	0	0.00	0.00
33	Gas		4,107				16,219	66,613	1,000,000	66,613	261,816	6.37	3.93
34	Plant Unit Info	790.0	4,107	0.7%	96.2%	37.2%	16,219			66,613	261,816	6.37	
35	Manatee 3												
36	Gas		343,679				7,542	2,592,139	1,000,000	2,592,139	10,205,607	2.97	3.94
37	Plant Unit Info	1,238.0	343,679	37.3%	94.1%	74.0%	7,542			2,592,139	10,205,607	2.97	
38	Manatee PV Solar												
39	Solar		16,600				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	16,600	30.0%	N/A	47.9%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		38,702				9,006	348,569	1,000,000	348,569	1,377,786	3.56	3.95
43	Plant Unit Info	476.0	38,702	10.9%	93.9%	80.5%	9,006			348,569	1,377,786	3.56	
44	Martin 4												
45	Gas		39,336				9,119	358,687	1,000,000	358,687	1,419,554	3.61	3.96
46	Plant Unit Info	476.0	39,336	11.1%	94.0%	68.3%	9,119			358,687	1,419,554	3.61	
47	Martin 8 Solar												
48	Solar		14,074				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	14,074	25.2%	N/A	46.6%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		289,918				7,716	2,237,036	1,000,000	2,237,036	8,816,924	3.04	3.94
53	Plant Unit Info	1,231.0	289,918	31.7%	94.0%	77.0%	7,716			2,237,036	8,816,924	3.04	
54	Miami-Dade PV Solar												
55	Solar		16,355				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	16,355	29.5%	N/A	54.5%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,134,556				6,171	7,001,348	1,000,000	7,001,348	27,958,953	2.46	3.99
60	Plant Unit Info	1,652.0	1,134,556	92.3%	96.7%	92.3%	6,171			7,001,348	27,958,953	2.46	

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		17,667				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	17,667	31.9%	N/A	58.8%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		373,701				6,428	2,402,050	1,000,000	2,402,050	9,576,442	2.56	3.99
7	Plant Unit Info	1,264.0	373,701	39.7%	41.5%	64.8%	6,428			2,402,050	9,576,442	2.56	
8	Pioneer Trail PV Solar												
9	Solar		16,829				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,829	30.4%	N/A	56.0%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		721,314				6,637	4,787,670	1,000,000	4,787,670	19,087,658	2.65	3.99
14	Plant Unit Info	1,309.0	721,314	74.1%	93.9%	74.1%	6,637			4,787,670	19,087,658	2.65	
15	Sanford 4												
16	Gas		178,399				7,712	1,375,798	1,000,000	1,375,798	5,483,270	3.07	3.99
17	Plant Unit Info	1,164.0	178,399	20.6%	48.8%	73.3%	7,712			1,375,798	5,483,270	3.07	
18	Sanford 5												
19	Gas		232,887				7,762	1,807,764	1,000,000	1,807,764	7,208,824	3.10	3.99
20	Plant Unit Info	1,164.0	232,887	26.9%	94.0%	73.8%	7,762			1,807,764	7,208,824	3.10	
21	Scherer 4												
22	Coal		183,652				11,436	123,541	17,000,000	2,100,191	5,317,088	2.90	43.04
23	Plant Unit Info	625.0	183,652	39.5%	94.8%	39.5%	11,436			2,100,191	5,317,088	2.90	
24	Southfork PV Solar												
25	Solar		21,623				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	21,623	39.0%	N/A	72.0%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,690				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,690	22.7%	N/A	38.9%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		711,664				10,560	7,515,172	1,000,000	7,515,172	3,519,378	0.49	0.47
32	Plant Unit Info	981.0	711,664	97.5%	97.5%	97.5%	10,560			7,515,172	3,519,378	0.49	
33	St Lucie 2												
34	Nuclear		609,290				10,496	6,395,109	1,000,000	6,395,109	2,809,243	0.46	0.44
35	Plant Unit Info	840.0	609,290	97.5%	97.5%	97.5%	10,496			6,395,109	2,809,243	0.46	
36	ST Project 1 Site 1												
37	Solar		15,082				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	15,082	27.2%	N/A	50.2%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		14,901				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	14,901	26.9%	N/A	49.6%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		19,198				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	19,198	34.6%	N/A	59.4%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		18,682				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	18,682	33.7%	N/A	57.8%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		15,469				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	15,469	27.9%	N/A	51.5%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		15,454				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	15,454	27.9%	N/A	51.5%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		17,493				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	17,493	31.4%	N/A	57.9%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		607,160				10,818	6,568,255	1,000,000	6,568,255	3,282,315	0.54	0.50
59	Plant Unit Info	837.0	607,160	97.5%	97.5%	97.5%	10,818			6,568,255	3,282,315	0.54	
60	Turkey Point 4												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		595,553				11,029	6,568,359	1,000,000	6,568,359	3,283,194	0.55	0.50
2	Plant Unit Info	821.0	595,553	97.5%	97.5%	97.5%	11,029			6,568,359	3,283,194	0.55	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		322,941				7,580	2,447,925	1,000,000	2,447,925	9,759,556	3.02	3.99
6	Plant Unit Info	1,248.0	322,941	34.8%	94.0%	71.9%	7,580			2,447,925	9,759,556	3.02	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		656,501				6,574	4,316,121	1,000,000	4,316,121	16,968,868	2.58	3.93
10	Plant Unit Info	1,264.0	656,501	69.8%	72.4%	69.8%	6,574			4,316,121	16,968,868	2.58	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		866,948				6,533	5,663,445	1,000,000	5,663,445	22,264,400	2.57	3.93
14	Plant Unit Info	1,264.0	866,948	92.2%	93.9%	92.2%	6,533			5,663,445	22,264,400	2.57	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		842,474				6,596	5,556,932	1,000,000	5,556,932	21,845,691	2.59	3.93
18	Plant Unit Info	1,247.0	842,474	90.8%	93.9%	90.8%	6,596			5,556,932	21,845,691	2.59	
19	Wildflower PV Solar												
20	Solar		16,748				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	16,748	30.2%	N/A	55.8%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,674	10,710,229				7,532			80,664,135	222,524,843	2.08	
24													
25													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		13,902				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,902	25.9%	N/A	41.5%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		14,259				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,259	26.6%	N/A	49.1%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		14,091				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,091	26.3%	N/A	48.5%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		794,847				6,591	5,238,478	1,000,000	5,238,478	20,216,359	2.54	3.86
14	Plant Unit Info	1,309.0	794,847	84.3%	93.9%	84.3%	6,591			5,238,478	20,216,359	2.54	
15	Citrus PV Solar												
16	Solar		14,087				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,087	26.3%	N/A	42.0%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		15,188				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	15,188	28.3%	N/A	52.3%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		4,355				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	4,355	24.2%	N/A	38.7%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		739,231				7,225	5,340,656	1,000,000	5,340,656	20,610,644	2.79	3.86
26	Plant Unit Info	1,774.0	739,231	57.9%	94.0%	57.9%	7,225			5,340,656	20,610,644	2.79	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		894				11,122	9,943	1,000,000	9,943	38,396	4.29	3.86
38	Plant Unit Info	215.0	894	0.6%	93.5%	83.5%	11,122			9,943	38,396	4.29	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		1,853				10,943	20,278	1,000,000	20,278	78,266	4.22	3.86
42	Plant Unit Info	215.0	1,853	1.2%	93.5%	86.4%	10,943			20,278	78,266	4.22	
43	Echo River PV Solar												
44	Solar		19,127				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	19,127	35.7%	N/A	57.1%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		13,802				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	13,802	25.7%	N/A	47.5%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		14,985				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	14,985	27.9%	N/A	51.6%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		15,217				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	15,217	28.4%	N/A	52.4%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		14,046				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	14,046	26.2%	N/A	48.4%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0										
60	Plant Unit Info		0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		14,384				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	14,384	26.8%	N/A	49.5%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		3,840				10,553	40,524	1,000,000	40,524	156,351	4.07	3.86
7	Plant Unit Info	215.0	3,840	2.5%	94.0%	94.0%	10,553			40,524	156,351	4.07	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		4,446				10,511	46,733	1,000,000	46,733	180,295	4.06	3.86
11	Plant Unit Info	215.0	4,446	2.9%	94.0%	93.9%	10,511			46,733	180,295	4.06	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		4,244				10,524	44,663	1,000,000	44,663	172,313	4.06	3.86
15	Plant Unit Info	215.0	4,244	2.7%	94.0%	93.9%	10,524			44,663	172,313	4.06	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		13,824				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,824	25.8%	N/A	47.6%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	790.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
31	Manatee 2												
32	Heavy Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	790.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
35	Manatee 3												
36	Gas		436,729				7,377	3,221,941	1,000,000	3,221,941	12,262,933	2.81	3.81
37	Plant Unit Info	1,238.0	436,729	49.0%	94.1%	75.2%	7,377			3,221,941	12,262,933	2.81	
38	Manatee PV Solar												
39	Solar		14,433				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	14,433	26.9%	N/A	43.1%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		43,363				8,282	359,151	1,000,000	359,151	1,386,923	3.20	3.86
43	Plant Unit Info	476.0	43,363	12.7%	93.9%	68.5%	8,282			359,151	1,386,923	3.20	
44	Martin 4												
45	Gas		37,449				8,238	308,514	1,000,000	308,514	1,192,235	3.18	3.86
46	Plant Unit Info	476.0	37,449	10.9%	94.0%	74.9%	8,238			308,514	1,192,235	3.18	
47	Martin 8 Solar												
48	Solar		13,260				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	13,260	24.6%	N/A	45.3%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		311,773				7,584	2,364,623	1,000,000	2,364,623	9,083,231	2.91	3.84
53	Plant Unit Info	1,231.0	311,773	35.2%	94.0%	79.1%	7,584			2,364,623	9,083,231	2.91	
54	Miami-Dade PV Solar												
55	Solar		13,593				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	13,593	25.3%	N/A	46.8%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,105,775				6,170	6,822,724	1,000,000	6,822,724	26,465,830	2.39	3.88
60	Plant Unit Info	1,652.0	1,105,775	93.0%	96.7%	93.0%	6,170			6,822,724	26,465,830	2.39	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		15,386				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	15,386	28.7%	N/A	52.9%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		715,455				6,356	4,547,652	1,000,000	4,547,652	17,551,751	2.45	3.86
7	Plant Unit Info	1,264.0	715,455	78.6%	82.2%	78.6%	6,356			4,547,652	17,551,751	2.45	
8	Pioneer Trail PV Solar												
9	Solar		14,277				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,277	26.6%	N/A	49.1%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		768,712				6,600	5,073,650	1,000,000	5,073,650	19,634,921	2.55	3.87
14	Plant Unit Info	1,309.0	768,712	81.5%	93.9%	81.5%	6,600			5,073,650	19,634,921	2.55	
15	Sanford 4												
16	Gas		226,045				7,694	1,739,121	1,000,000	1,739,121	6,714,198	2.97	3.86
17	Plant Unit Info	1,164.0	226,045	27.0%	94.0%	71.9%	7,694			1,739,121	6,714,198	2.97	
18	Sanford 5												
19	Gas		249,511				7,665	1,912,450	1,000,000	1,912,450	7,383,663	2.96	3.86
20	Plant Unit Info	1,164.0	249,511	29.8%	94.0%	69.6%	7,665			1,912,450	7,383,663	2.96	
21	Scherer 4												
22	Coal		179,304				11,420	120,452	17,000,000	2,047,679	5,187,421	2.89	43.07
23	Plant Unit Info	625.0	179,304	39.9%	94.8%	39.9%	11,420			2,047,679	5,187,421	2.89	
24	Southfork PV Solar												
25	Solar		18,398				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	18,398	34.3%	N/A	63.3%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,447				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,447	20.1%	N/A	32.2%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		688,707				10,560	7,272,748	1,000,000	7,272,748	3,405,849	0.49	0.47
32	Plant Unit Info	981.0	688,707	97.5%	97.5%	97.5%	10,560			7,272,748	3,405,849	0.49	
33	St Lucie 2												
34	Nuclear		589,635				10,496	6,188,815	1,000,000	6,188,815	2,718,623	0.46	0.44
35	Plant Unit Info	840.0	589,635	97.5%	97.5%	97.5%	10,496			6,188,815	2,718,623	0.46	
36	ST Project 1 Site 1												
37	Solar		12,407				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	12,407	23.1%	N/A	42.7%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		12,290				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	12,290	22.9%	N/A	42.3%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		15,362				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	15,362	28.6%	N/A	49.1%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		14,949				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	14,949	27.9%	N/A	47.8%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		12,759				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	12,759	23.8%	N/A	43.9%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		12,746				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	12,746	23.8%	N/A	43.9%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		15,048				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	15,048	27.9%	N/A	47.8%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		587,574				10,818	6,356,376	1,000,000	6,356,376	3,176,434	0.54	0.50
59	Plant Unit Info	837.0	587,574	97.5%	97.5%	97.5%	10,818			6,356,376	3,176,434	0.54	
60	Turkey Point 4												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		576,342				11,029	6,356,476	1,000,000	6,356,476	3,177,285	0.55	0.50
2	Plant Unit Info	821.0	576,342	97.5%	97.5%	97.5%	11,029			6,356,476	3,177,285	0.55	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		357,461				7,472	2,670,785	1,000,000	2,670,785	10,308,107	2.88	3.86
6	Plant Unit Info	1,248.0	357,461	39.8%	94.0%	70.0%	7,472			2,670,785	10,308,107	2.88	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		835,993				6,537	5,464,721	1,000,000	5,464,721	20,784,030	2.49	3.80
10	Plant Unit Info	1,264.0	835,993	91.9%	93.9%	91.9%	6,537			5,464,721	20,784,030	2.49	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		824,979				6,547	5,401,480	1,000,000	5,401,480	20,543,568	2.49	3.80
14	Plant Unit Info	1,264.0	824,979	90.7%	93.9%	90.7%	6,547			5,401,480	20,543,568	2.49	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		812,103				6,602	5,361,823	1,000,000	5,361,823	20,392,756	2.51	3.80
18	Plant Unit Info	1,247.0	812,103	90.5%	93.9%	90.5%	6,602			5,361,823	20,392,756	2.51	
19	Wildflower PV Solar												
20	Solar		13,938				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,938	26.0%	N/A	48.0%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,674	11,277,825				7,467			84,212,004	232,822,382	2.06	

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Appendix II - 2020 FCR Projections
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		14,422				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,422	26.0%	N/A	41.6%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		15,828				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,828	28.6%	N/A	52.7%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		15,378				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,378	27.7%	N/A	51.2%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		775,803				6,617	5,133,280	1,000,000	5,133,280	19,577,531	2.52	3.81
14	Plant Unit Info	1,309.0	775,803	79.6%	93.9%	79.6%	6,617			5,133,280	19,577,531	2.52	
15	Citrus PV Solar												
16	Solar		14,808				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,808	26.7%	N/A	42.8%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		15,863				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	15,863	28.6%	N/A	52.8%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		4,546				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	4,546	24.4%	N/A	41.9%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		781,392				7,239	5,656,528	1,000,000	5,656,528	21,569,779	2.76	3.81
26	Plant Unit Info	1,774.0	781,392	59.2%	94.0%	59.2%	7,239			5,656,528	21,569,779	2.76	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		22				10,604	41	5,830,000	238	3,859	17.19	94.52
37	Gas		7,814				10,604	82,852	1,000,000	82,852	316,093	4.05	3.82
38	Plant Unit Info	215.0	7,836	4.9%	93.5%	93.5%	10,604			83,090	319,952	4.08	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		7,036				10,599	74,578	1,000,000	74,578	284,569	4.04	3.82
42	Plant Unit Info	215.0	7,036	4.4%	93.5%	93.5%	10,599			74,578	284,569	4.04	
43	Echo River PV Solar												
44	Solar		19,942				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	19,942	36.0%	N/A	61.7%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		15,030				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	15,030	27.1%	N/A	50.1%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		15,689				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	15,689	28.3%	N/A	52.2%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		15,883				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	15,883	28.7%	N/A	52.9%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		15,327				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	15,327	27.7%	N/A	51.0%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0					0	0	0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		15,282				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	15,282	27.6%	N/A	50.9%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		15,360				10,534	161,795	1,000,000	161,795	617,135	4.02	3.81
7	Plant Unit Info	215.0	15,360	9.6%	94.0%	94.0%	10,534			161,795	617,135	4.02	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		14,349				10,555	151,447	1,000,000	151,447	577,278	4.02	3.81
11	Plant Unit Info	215.0	14,349	9.0%	94.0%	94.0%	10,555			151,447	577,278	4.02	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		13,137				10,537	138,429	1,000,000	138,429	527,680	4.02	3.81
15	Plant Unit Info	215.0	13,137	8.2%	94.0%	94.0%	10,537			138,429	527,680	4.02	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		15,192				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,192	27.4%	N/A	50.6%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		11,020				12,691	139,855	1,000,000	139,855	526,086	4.77	3.76
30	Plant Unit Info	790.0	11,020	1.9%	96.2%	32.4%	12,691			139,855	526,086	4.77	
31	Manatee 2												
32	Heavy Oil		0					0	0	0	0	0.00	0.00
33	Gas		28,790				11,402	328,258	1,000,000	328,258	1,237,610	4.30	3.77
34	Plant Unit Info	790.0	28,790	4.9%	96.2%	30.9%	11,402			328,258	1,237,610	4.30	
35	Manatee 3												
36	Gas		443,768				7,403	3,285,436	1,000,000	3,285,436	12,352,712	2.78	3.76
37	Plant Unit Info	1,238.0	443,768	48.2%	94.1%	73.6%	7,403			3,285,436	12,352,712	2.78	
38	Manatee PV Solar												
39	Solar		14,533				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	14,533	26.2%	N/A	42.0%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		80,089				8,238	659,783	1,000,000	659,783	2,514,667	3.14	3.81
43	Plant Unit Info	476.0	80,089	22.6%	93.9%	68.7%	8,238			659,783	2,514,667	3.14	
44	Martin 4												
45	Gas		85,623				8,234	705,042	1,000,000	705,042	2,684,825	3.14	3.81
46	Plant Unit Info	476.0	85,623	24.2%	94.0%	72.0%	8,234			705,042	2,684,825	3.14	
47	Martin 8 Solar												
48	Solar		12,679				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	12,679	22.7%	N/A	36.4%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		403,024				7,482	3,015,427	1,000,000	3,015,427	11,482,943	2.85	3.81
53	Plant Unit Info	1,231.0	403,024	44.0%	94.0%	79.6%	7,482			3,015,427	11,482,943	2.85	
54	Miami-Dade PV Solar												
55	Solar		14,902				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	14,902	26.9%	N/A	49.6%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,144,974				6,170	7,064,161	1,000,000	7,064,161	27,056,777	2.36	3.83
60	Plant Unit Info	1,652.0	1,144,974	93.2%	96.7%	93.2%	6,170			7,064,161	27,056,777	2.36	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		16,177				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	16,177	29.2%	N/A	53.9%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		873,614				6,326	5,526,747	1,000,000	5,526,747	21,076,526	2.41	3.81
7	Plant Unit Info	1,264.0	873,614	92.9%	93.9%	92.9%	6,326			5,526,747	21,076,526	2.41	
8	Pioneer Trail PV Solar												
9	Solar		15,160				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,160	27.4%	N/A	50.5%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		830,992				6,581	5,468,845	1,000,000	5,468,845	20,923,760	2.52	3.83
14	Plant Unit Info	1,309.0	830,992	85.3%	93.9%	85.3%	6,581			5,468,845	20,923,760	2.52	
15	Sanford 4												
16	Gas		311,418				7,651	2,382,611	1,000,000	2,382,611	9,086,701	2.92	3.81
17	Plant Unit Info	1,164.0	311,418	36.0%	94.0%	71.9%	7,651			2,382,611	9,086,701	2.92	
18	Sanford 5												
19	Gas		242,521				7,588	1,840,253	1,000,000	1,840,253	7,017,845	2.89	3.81
20	Plant Unit Info	1,164.0	242,521	28.0%	94.0%	58.7%	7,588			1,840,253	7,017,845	2.89	
21	Scherer 4												
22	Coal		194,057				11,348	129,536	17,000,000	2,202,108	5,595,227	2.88	43.19
23	Plant Unit Info	625.0	194,057	41.7%	94.8%	41.7%	11,348			2,202,108	5,595,227	2.88	
24	Southfork PV Solar												
25	Solar		18,794				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	18,794	33.9%	N/A	62.6%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,555				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,555	20.9%	N/A	33.4%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		711,664				10,560	7,515,172	1,000,000	7,515,172	3,519,378	0.49	0.47
32	Plant Unit Info	981.0	711,664	97.5%	97.5%	97.5%	10,560			7,515,172	3,519,378	0.49	
33	St Lucie 2												
34	Nuclear		609,290				10,496	6,395,109	1,000,000	6,395,109	2,809,243	0.46	0.44
35	Plant Unit Info	840.0	609,290	97.5%	97.5%	97.5%	10,496			6,395,109	2,809,243	0.46	
36	ST Project 1 Site 1												
37	Solar		13,905				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	13,905	25.1%	N/A	46.3%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		13,402				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	13,402	24.2%	N/A	44.6%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		16,889				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	16,889	30.5%	N/A	56.3%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		16,435				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	16,435	29.7%	N/A	54.7%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		13,913				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	13,913	25.1%	N/A	46.3%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		13,900				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	13,900	25.1%	N/A	46.3%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		16,102				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	16,102	28.9%	N/A	49.5%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		607,160				10,818	6,568,255	1,000,000	6,568,255	3,282,315	0.54	0.50
59	Plant Unit Info	837.0	607,160	97.5%	97.5%	97.5%	10,818			6,568,255	3,282,315	0.54	
60	Turkey Point 4												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		595,553				11,029	6,568,359	1,000,000	6,568,359	3,283,194	0.55	0.50
2	Plant Unit Info	821.0	595,553	97.5%	97.5%	97.5%	11,029			6,568,359	3,283,194	0.55	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		412,077				7,457	3,072,908	1,000,000	3,072,908	11,716,303	2.84	3.81
6	Plant Unit Info	1,248.0	412,077	44.4%	94.0%	67.5%	7,457			3,072,908	11,716,303	2.84	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		860,940				6,539	5,630,091	1,000,000	5,630,091	21,149,072	2.46	3.76
10	Plant Unit Info	1,264.0	860,940	91.6%	93.9%	91.6%	6,539			5,630,091	21,149,072	2.46	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		830,772				6,566	5,454,675	1,000,000	5,454,675	20,490,184	2.47	3.76
14	Plant Unit Info	1,264.0	830,772	88.3%	93.9%	88.3%	6,566			5,454,675	20,490,184	2.47	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		837,092				6,605	5,528,590	1,000,000	5,528,590	20,767,811	2.48	3.76
18	Plant Unit Info	1,247.0	837,092	90.2%	93.9%	90.2%	6,605			5,528,590	20,767,811	2.48	
19	Wildflower PV Solar												
20	Solar		15,120				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	15,120	27.3%	N/A	50.4%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,674	12,136,007				7,478			90,750,833	252,047,102	2.08	
24													
25													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		14,342				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,342	25.9%	N/A	41.4%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		15,006				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,006	27.1%	N/A	50.0%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		14,520				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,520	26.2%	N/A	48.4%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		764,159				6,619	5,058,065	1,000,000	5,058,065	19,495,235	2.55	3.85
14	Plant Unit Info	1,309.0	764,159	78.4%	93.9%	78.4%	6,619			5,058,065	19,495,235	2.55	
15	Citrus PV Solar												
16	Solar		14,610				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,610	26.4%	N/A	45.2%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		15,308				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	15,308	27.6%	N/A	51.0%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		4,326				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	4,326	23.3%	N/A	39.9%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		782,343				7,229	5,655,542	1,000,000	5,655,542	21,794,897	2.79	3.85
26	Plant Unit Info	1,774.0	782,343	59.3%	94.0%	59.3%	7,229			5,655,542	21,794,897	2.79	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		7,473				10,674	79,766	1,000,000	79,766	307,427	4.11	3.85
38	Plant Unit Info	215.0	7,473	4.7%	93.5%	91.4%	10,674			79,766	307,427	4.11	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		8,332				10,639	88,646	1,000,000	88,646	341,594	4.10	3.85
42	Plant Unit Info	215.0	8,332	5.2%	93.5%	92.3%	10,639			88,646	341,594	4.10	
43	Echo River PV Solar												
44	Solar		18,710				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	18,710	33.8%	N/A	62.3%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		14,510				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	14,510	26.2%	N/A	48.3%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		15,424				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	15,424	27.8%	N/A	51.4%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		15,311				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	15,311	27.6%	N/A	51.0%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		14,470				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	14,470	26.1%	N/A	48.2%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0					0	0	0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		15,103				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	15,103	27.3%	N/A	50.3%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		15,764				10,526	165,934	1,000,000	165,934	639,653	4.06	3.85
7	Plant Unit Info	215.0	15,764	9.9%	94.0%	94.0%	10,526			165,934	639,653	4.06	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		15,562				10,511	163,565	1,000,000	163,565	630,740	4.05	3.86
11	Plant Unit Info	215.0	15,562	9.7%	94.0%	94.0%	10,511			163,565	630,740	4.05	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		15,158				10,537	159,725	1,000,000	159,725	615,644	4.06	3.85
15	Plant Unit Info	215.0	15,158	9.5%	94.0%	94.0%	10,537			159,725	615,644	4.06	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		14,495				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,495	26.2%	N/A	48.3%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		2,016				11,933	3,759	6,400,000	24,059	276,422	13.71	73.53
29	Gas		28,845				11,933	344,211	1,000,000	344,211	1,313,514	4.55	3.82
30	Plant Unit Info	790.0	30,861	5.3%	96.2%	32.6%	11,933			368,270	1,589,937	5.15	
31	Manatee 2												
32	Heavy Oil		1,562				11,257	2,748	6,400,000	17,585	202,040	12.93	73.53
33	Gas		46,223				11,257	520,354	1,000,000	520,354	1,980,756	4.29	3.81
34	Plant Unit Info	790.0	47,785	8.1%	96.2%	31.5%	11,257			537,939	2,182,796	4.57	
35	Manatee 3												
36	Gas		437,889				7,394	3,237,572	1,000,000	3,237,572	12,307,494	2.81	3.80
37	Plant Unit Info	1,238.0	437,889	47.5%	94.1%	71.5%	7,394			3,237,572	12,307,494	2.81	
38	Manatee PV Solar												
39	Solar		14,390				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	14,390	26.0%	N/A	44.5%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		94,780				8,132	770,710	1,000,000	770,710	2,971,395	3.14	3.86
43	Plant Unit Info	476.0	94,780	26.8%	93.9%	69.1%	8,132			770,710	2,971,395	3.14	
44	Martin 4												
45	Gas		87,992				8,177	719,554	1,000,000	719,554	2,775,804	3.15	3.86
46	Plant Unit Info	476.0	87,992	24.9%	94.0%	68.0%	8,177			719,554	2,775,804	3.15	
47	Martin 8 Solar												
48	Solar		11,873				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	11,873	21.3%	N/A	39.3%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		415,393				7,556	3,138,898	1,000,000	3,138,898	12,073,213	2.91	3.85
53	Plant Unit Info	1,231.0	415,393	45.4%	94.0%	80.9%	7,556			3,138,898	12,073,213	2.91	
54	Miami-Dade PV Solar												
55	Solar		14,748				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	14,748	26.6%	N/A	49.1%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,144,392				6,170	7,060,525	1,000,000	7,060,525	27,334,606	2.39	3.87
60	Plant Unit Info	1,652.0	1,144,392	93.1%	96.7%	93.1%	6,170			7,060,525	27,334,606	2.39	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		15,842				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	15,842	28.6%	N/A	52.8%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		877,705				6,324	5,550,464	1,000,000	5,550,464	21,390,897	2.44	3.85
7	Plant Unit Info	1,264.0	877,705	93.3%	93.9%	93.3%	6,324			5,550,464	21,390,897	2.44	
8	Pioneer Trail PV Solar												
9	Solar		15,040				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,040	27.1%	N/A	50.1%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		814,178				6,587	5,363,392	1,000,000	5,363,392	20,737,488	2.55	3.87
14	Plant Unit Info	1,309.0	814,178	83.6%	93.9%	83.6%	6,587			5,363,392	20,737,488	2.55	
15	Sanford 4												
16	Gas		315,743				7,506	2,369,842	1,000,000	2,369,842	9,132,157	2.89	3.85
17	Plant Unit Info	1,164.0	315,743	36.5%	94.0%	68.5%	7,506			2,369,842	9,132,157	2.89	
18	Sanford 5												
19	Gas		285,454				7,675	2,190,794	1,000,000	2,190,794	8,442,455	2.96	3.85
20	Plant Unit Info	1,164.0	285,454	33.0%	94.0%	70.5%	7,675			2,190,794	8,442,455	2.96	
21	Scherer 4												
22	Coal		196,002				11,336	130,698	17,000,000	2,221,874	5,667,262	2.89	43.36
23	Plant Unit Info	625.0	196,002	42.2%	94.8%	42.2%	11,336			2,221,874	5,667,262	2.89	
24	Southfork PV Solar												
25	Solar		18,357				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	18,357	33.1%	N/A	61.1%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,545				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,545	20.8%	N/A	38.3%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		711,664				10,560	7,515,172	1,000,000	7,515,172	3,519,378	0.49	0.47
32	Plant Unit Info	981.0	711,664	97.5%	97.5%	97.5%	10,560			7,515,172	3,519,378	0.49	
33	St Lucie 2												
34	Nuclear		609,290				10,496	6,395,109	1,000,000	6,395,109	2,809,243	0.46	0.44
35	Plant Unit Info	840.0	609,290	97.5%	97.5%	97.5%	10,496			6,395,109	2,809,243	0.46	
36	ST Project 1 Site 1												
37	Solar		13,274				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	13,274	24.0%	N/A	44.2%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		12,982				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	12,982	23.4%	N/A	43.2%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		15,651				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	15,651	28.2%	N/A	52.1%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		15,230				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	15,230	27.5%	N/A	50.7%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		13,478				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	13,478	24.3%	N/A	44.9%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		13,465				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	13,465	24.3%	N/A	44.8%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		15,207				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	15,207	27.3%	N/A	50.3%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		607,160				10,818	6,568,255	1,000,000	6,568,255	3,282,315	0.54	0.50
59	Plant Unit Info	837.0	607,160	97.5%	97.5%	97.5%	10,818			6,568,255	3,282,315	0.54	
60	Turkey Point 4												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		595,553				11,029	6,568,359	1,000,000	6,568,359	3,283,194	0.55	0.50
2	Plant Unit Info	821.0	595,553	97.5%	97.5%	97.5%	11,029			6,568,359	3,283,194	0.55	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		367,874				7,542	2,774,665	1,000,000	2,774,665	10,694,586	2.91	3.85
6	Plant Unit Info	1,248.0	367,874	39.6%	94.0%	70.5%	7,542			2,774,665	10,694,586	2.91	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		863,759				6,537	5,646,298	1,000,000	5,646,298	21,427,029	2.48	3.79
10	Plant Unit Info	1,264.0	863,759	91.9%	93.9%	91.9%	6,537			5,646,298	21,427,029	2.48	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		829,625				6,566	5,446,988	1,000,000	5,446,988	20,670,596	2.49	3.79
14	Plant Unit Info	1,264.0	829,625	88.2%	93.9%	88.2%	6,566			5,446,988	20,670,596	2.49	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		838,225				6,603	5,535,058	1,000,000	5,535,058	21,004,853	2.51	3.79
18	Plant Unit Info	1,247.0	838,225	90.4%	93.9%	90.4%	6,603			5,535,058	21,004,853	2.51	
19	Wildflower PV Solar												
20	Solar		14,535				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	14,535	26.2%	N/A	48.4%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,674	12,171,867				7,505			91,350,982	257,121,888	2.11	
24													
25													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		13,329				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,329	24.9%	N/A	45.9%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		13,946				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,946	26.0%	N/A	48.0%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		13,613				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,613	25.4%	N/A	46.9%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		802,104				6,589	5,284,682	1,000,000	5,284,682	20,556,657	2.56	3.89
14	Plant Unit Info	1,309.0	802,104	85.1%	93.9%	85.1%	6,589			5,284,682	20,556,657	2.56	
15	Citrus PV Solar												
16	Solar		13,630				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	13,630	25.4%	N/A	46.9%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		13,851				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	13,851	25.8%	N/A	47.7%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		3,868				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	3,868	21.5%	N/A	39.7%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		704,356				7,180	5,057,440	1,000,000	5,057,440	19,673,192	2.79	3.89
26	Plant Unit Info	1,774.0	704,356	55.1%	78.4%	55.1%	7,180			5,057,440	19,673,192	2.79	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	N/A			N/A	N/A	N/A	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	N/A			N/A	N/A	N/A	
35	Fort Myers 3C												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		4,423				10,529	46,569	1,000,000	46,569	181,706	4.11	3.90
38	Plant Unit Info	215.0	4,423	2.9%	93.5%	93.6%	10,529			46,569	181,706	4.11	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		6,835				10,566	72,216	1,000,000	72,216	281,674	4.12	3.90
42	Plant Unit Info	215.0	6,835	4.4%	93.5%	93.6%	10,566			72,216	281,674	4.12	
43	Echo River PV Solar												
44	Solar		16,335				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	16,335	30.5%	N/A	56.2%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		13,662				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	13,662	25.5%	N/A	47.0%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		13,975				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	13,975	26.1%	N/A	48.1%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		14,046				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	14,046	26.2%	N/A	48.4%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		13,569				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	13,569	25.3%	N/A	46.7%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0					0	0	0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		14,077				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	14,077	26.2%	N/A	48.4%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		12,732				10,524	133,989	1,000,000	133,989	522,037	4.10	3.90
7	Plant Unit Info	215.0	12,732	8.2%	94.0%	93.9%	10,524			133,989	522,037	4.10	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		11,924				10,518	125,411	1,000,000	125,411	488,639	4.10	3.90
11	Plant Unit Info	215.0	11,924	7.7%	94.0%	94.0%	10,518			125,411	488,639	4.10	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		11,722				10,522	123,341	1,000,000	123,341	480,652	4.10	3.90
15	Plant Unit Info	215.0	11,722	7.6%	94.0%	94.0%	10,522			123,341	480,652	4.10	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	N/A			N/A	N/A	N/A	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	N/A			N/A	N/A	N/A	
24	Loggerhead PV Solar												
25	Solar		13,706				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,706	25.6%	N/A	47.2%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		1,341				11,548	2,420	6,400,000	15,490	177,970	13.27	73.53
29	Gas		33,381				11,548	385,472	1,000,000	385,472	1,481,759	4.44	3.84
30	Plant Unit Info	790.0	34,722	6.1%	96.2%	30.9%	11,548			400,962	1,659,729	4.78	
31	Manatee 2												
32	Heavy Oil		1,911				11,584	3,459	6,400,000	22,137	254,340	13.31	73.53
33	Gas		15,838				11,584	183,470	1,000,000	183,470	708,981	4.48	3.86
34	Plant Unit Info	790.0	17,749	3.1%	96.2%	35.1%	11,584			205,607	963,321	5.43	
35	Manatee 3												
36	Gas		487,895				7,189	3,507,583	1,000,000	3,507,583	13,453,109	2.76	3.84
37	Plant Unit Info	1,238.0	487,895	54.7%	94.1%	71.0%	7,189			3,507,583	13,453,109	2.76	
38	Manatee PV Solar												
39	Solar		13,677				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	13,677	25.5%	N/A	47.1%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		68,968				8,155	562,411	1,000,000	562,411	2,173,087	3.15	3.86
43	Plant Unit Info	476.0	68,968	20.1%	93.9%	72.8%	8,155			562,411	2,173,087	3.15	
44	Martin 4												
45	Gas		75,136				8,128	610,698	1,000,000	610,698	2,361,591	3.14	3.87
46	Plant Unit Info	476.0	75,136	21.9%	94.0%	71.4%	8,128			610,698	2,361,591	3.14	
47	Martin 8 Solar												
48	Solar		10,320				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	10,320	19.1%	N/A	35.3%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		469,314				7,361	3,454,495	1,000,000	3,454,495	13,302,882	2.83	3.85
53	Plant Unit Info	1,231.0	469,314	52.9%	94.0%	78.4%	7,361			3,454,495	13,302,882	2.83	
54	Miami-Dade PV Solar												
55	Solar		13,518				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	13,518	25.2%	N/A	46.5%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,110,018				6,170	6,849,307	1,000,000	6,849,307	26,774,698	2.41	3.91
60	Plant Unit Info	1,652.0	1,110,018	93.3%	96.7%	93.3%	6,170			6,849,307	26,774,698	2.41	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		14,608				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	14,608	27.2%	N/A	50.3%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		846,432				6,326	5,354,298	1,000,000	5,354,298	20,827,127	2.46	3.89
7	Plant Unit Info	1,264.0	846,432	93.0%	93.9%	93.0%	6,326			5,354,298	20,827,127	2.46	
8	Pioneer Trail PV Solar												
9	Solar		13,666				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,666	25.5%	N/A	47.0%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		803,132				6,584	5,287,578	1,000,000	5,287,578	20,636,108	2.57	3.90
14	Plant Unit Info	1,309.0	803,132	85.2%	93.9%	85.2%	6,584			5,287,578	20,636,108	2.57	
15	Sanford 4												
16	Gas		328,081				7,475	2,452,257	1,000,000	2,452,257	9,539,675	2.91	3.89
17	Plant Unit Info	1,164.0	328,081	39.2%	94.0%	67.4%	7,475			2,452,257	9,539,675	2.91	
18	Sanford 5												
19	Gas		292,691				7,455	2,181,980	1,000,000	2,181,980	8,489,920	2.90	3.89
20	Plant Unit Info	1,164.0	292,691	34.9%	94.0%	65.5%	7,455			2,181,980	8,489,920	2.90	
21	Scherer 4												
22	Coal		184,272				11,380	123,359	17,000,000	2,097,104	5,362,555	2.91	43.47
23	Plant Unit Info	625.0	184,272	41.0%	94.8%	41.0%	11,380			2,097,104	5,362,555	2.91	
24	Southfork PV Solar												
25	Solar		16,374				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	16,374	30.5%	N/A	56.4%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,421				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,421	19.7%	N/A	36.4%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		688,707				10,560	7,272,748	1,000,000	7,272,748	3,405,849	0.49	0.47
32	Plant Unit Info	981.0	688,707	97.5%	97.5%	97.5%	10,560			7,272,748	3,405,849	0.49	
33	St Lucie 2												
34	Nuclear		589,635				10,496	6,188,815	1,000,000	6,188,815	2,718,623	0.46	0.44
35	Plant Unit Info	840.0	589,635	97.5%	97.5%	97.5%	10,496			6,188,815	2,718,623	0.46	
36	ST Project 1 Site 1												
37	Solar		12,663				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	12,663	23.6%	N/A	43.6%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		12,314				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	12,314	23.0%	N/A	42.4%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		14,415				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	14,415	26.9%	N/A	49.6%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		14,028				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	14,028	26.2%	N/A	48.3%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		12,783				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	12,783	23.8%	N/A	44.0%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		12,771				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	12,771	23.8%	N/A	44.0%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		14,124				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	14,124	26.2%	N/A	48.3%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		587,574				10,818	6,356,376	1,000,000	6,356,376	3,176,434	0.54	0.50
59	Plant Unit Info	837.0	587,574	97.5%	97.5%	97.5%	10,818			6,356,376	3,176,434	0.54	
60	Turkey Point 4												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		576,342				11,029	6,356,476	1,000,000	6,356,476	3,177,285	0.55	0.50
2	Plant Unit Info	821.0	576,342	97.5%	97.5%	97.5%	11,029			6,356,476	3,177,285	0.55	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		290,340				7,414	2,152,672	1,000,000	2,152,672	8,371,643	2.88	3.89
6	Plant Unit Info	1,248.0	290,340	32.3%	62.3%	60.1%	7,414			2,152,672	8,371,643	2.88	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		838,836				6,534	5,481,225	1,000,000	5,481,225	21,008,241	2.50	3.83
10	Plant Unit Info	1,264.0	838,836	92.2%	93.9%	92.2%	6,534			5,481,225	21,008,241	2.50	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		832,172				6,541	5,442,963	1,000,000	5,442,963	20,861,615	2.51	3.83
14	Plant Unit Info	1,264.0	832,172	91.4%	93.9%	91.4%	6,541			5,442,963	20,861,615	2.51	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		227,134				6,712	1,524,493	1,000,000	1,524,493	5,843,244	2.57	3.83
18	Plant Unit Info	1,247.0	227,134	21.7%	21.7%	63.3%	6,712			1,524,493	5,843,244	2.57	
19	Wildflower PV Solar												
20	Solar		13,973				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,973	26.1%	N/A	48.1%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,674	11,265,508				7,508			84,583,696	236,291,294	2.10	
24													
25													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		13,941				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,941	25.2%	N/A	46.4%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		14,297				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,297	25.8%	N/A	51.6%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		13,834				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,834	25.0%	N/A	49.9%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		689,581				6,675	4,602,612	1,000,000	4,602,612	18,529,465	2.69	4.03
14	Plant Unit Info	1,309.0	689,581	70.8%	93.9%	70.8%	6,675			4,602,612	18,529,465	2.69	
15	Citrus PV Solar												
16	Solar		14,046				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,046	25.3%	N/A	46.8%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		14,221				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	14,221	25.7%	N/A	51.3%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		3,833				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	3,833	20.6%	N/A	41.2%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		805,061				7,203	5,798,572	1,000,000	5,798,572	23,344,891	2.90	4.03
26	Plant Unit Info	1,774.0	805,061	61.0%	94.0%	61.0%	7,203			5,798,572	23,344,891	2.90	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	190.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		1				10,568	2	5,830,000	11	178	17.14	94.52
37	Gas		4,824				10,568	50,982	1,000,000	50,982	205,688	4.26	4.03
38	Plant Unit Info	215.0	4,825	3.0%	93.5%	93.6%	10,568			50,993	205,866	4.27	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		3,015				10,558	31,833	1,000,000	31,833	128,838	4.27	4.05
42	Plant Unit Info	215.0	3,015	1.9%	93.5%	93.7%	10,558			31,833	128,838	4.27	
43	Echo River PV Solar												
44	Solar		16,339				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	16,339	29.5%	N/A	59.0%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		14,535				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	14,535	26.2%	N/A	52.4%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		13,972				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	13,972	25.2%	N/A	50.4%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		14,366				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	14,366	25.9%	N/A	51.8%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		13,789				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	13,789	24.9%	N/A	49.8%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0					0	0	0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		14,239				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	14,239	25.7%	N/A	51.4%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		11,924				10,518	125,411	1,000,000	125,411	505,444	4.24	4.03
7	Plant Unit Info	215.0	11,924	7.5%	94.0%	93.9%	10,518			125,411	505,444	4.24	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		11,520				10,527	121,271	1,000,000	121,271	488,809	4.24	4.03
11	Plant Unit Info	215.0	11,520	7.2%	94.0%	94.0%	10,527			121,271	488,809	4.24	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		11,318				10,532	119,201	1,000,000	119,201	480,440	4.24	4.03
15	Plant Unit Info	215.0	11,318	7.1%	94.0%	94.1%	10,532			119,201	480,440	4.24	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	215.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		14,102				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,102	25.4%	N/A	50.9%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		12,946				11,494	148,802	1,000,000	148,802	590,507	4.56	3.97
30	Plant Unit Info	790.0	12,946	2.2%	96.2%	30.9%	11,494			148,802	590,507	4.56	
31	Manatee 2												
32	Heavy Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	790.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
35	Manatee 3												
36	Gas		584,971				6,990	4,089,147	1,000,000	4,089,147	16,237,733	2.78	3.97
37	Plant Unit Info	1,238.0	584,971	63.5%	94.1%	66.6%	6,990			4,089,147	16,237,733	2.78	
38	Manatee PV Solar												
39	Solar		14,472				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	14,472	26.1%	N/A	48.2%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		116,610				7,898	920,968	1,000,000	920,968	3,661,452	3.14	3.98
43	Plant Unit Info	476.0	116,610	32.9%	93.9%	69.0%	7,898			920,968	3,661,452	3.14	
44	Martin 4												
45	Gas		0					0	0	0	0	0.00	0.00
46	Plant Unit Info	476.0	0	0.0%	N/A	0.0%	0			0	0	0.00	
47	Martin 8 Solar												
48	Solar		9,114				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	9,114	16.3%	N/A	30.1%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		544,799				7,154	3,897,547	1,000,000	3,897,547	15,483,859	2.84	3.97
53	Plant Unit Info	1,231.0	544,799	59.5%	94.0%	72.4%	7,154			3,897,547	15,483,859	2.84	
54	Miami-Dade PV Solar												
55	Solar		13,970				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	13,970	25.2%	N/A	50.4%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,119,618				6,182	6,921,207	1,000,000	6,921,207	27,965,562	2.50	4.04
60	Plant Unit Info	1,652.0	1,119,618	91.1%	96.7%	91.1%	6,182			6,921,207	27,965,562	2.50	

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		14,662				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	14,662	26.5%	N/A	52.9%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		846,386				6,349	5,373,920	1,000,000	5,373,920	21,634,493	2.56	4.03
7	Plant Unit Info	1,264.0	846,386	90.0%	93.9%	90.0%	6,349			5,373,920	21,634,493	2.56	
8	Pioneer Trail PV Solar												
9	Solar		13,578				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,578	24.5%	N/A	49.0%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		323,473				6,654	2,152,462	1,000,000	2,152,462	8,687,754	2.69	4.04
14	Plant Unit Info	1,309.0	323,473	33.2%	39.1%	73.5%	6,654			2,152,462	8,687,754	2.69	
15	Sanford 4												
16	Gas		383,989				7,333	2,815,867	1,000,000	2,815,867	11,340,389	2.95	4.03
17	Plant Unit Info	1,164.0	383,989	44.3%	94.0%	62.4%	7,333			2,815,867	11,340,389	2.95	
18	Sanford 5												
19	Gas		370,835				7,367	2,731,829	1,000,000	2,731,829	10,999,419	2.97	4.03
20	Plant Unit Info	1,164.0	370,835	42.8%	94.0%	65.7%	7,367			2,731,829	10,999,419	2.97	
21	Scherer 4												
22	Coal		189,929				11,382	127,167	17,000,000	2,161,833	5,539,209	2.92	43.56
23	Plant Unit Info	625.0	189,929	40.8%	94.8%	40.8%	11,382			2,161,833	5,539,209	2.92	
24	Southfork PV Solar												
25	Solar		16,729				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	16,729	30.2%	N/A	60.4%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,451				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,451	19.5%	N/A	39.0%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		711,664				10,560	7,515,172	1,000,000	7,515,172	3,519,378	0.49	0.47
32	Plant Unit Info	981.0	711,664	97.5%	97.5%	97.5%	10,560			7,515,172	3,519,378	0.49	
33	St Lucie 2												
34	Nuclear		609,290				10,496	6,395,109	1,000,000	6,395,109	2,809,243	0.46	0.44
35	Plant Unit Info	840.0	609,290	97.5%	97.5%	97.5%	10,496			6,395,109	2,809,243	0.46	
36	ST Project 1 Site 1												
37	Solar		13,027				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	13,027	23.5%	N/A	47.0%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		12,992				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	12,992	23.4%	N/A	46.9%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		14,269				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	14,269	25.7%	N/A	51.5%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		13,886				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	13,886	25.1%	N/A	50.1%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		13,488				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	13,488	24.3%	N/A	48.7%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		13,475				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	13,475	24.3%	N/A	48.6%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		14,265				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	14,265	25.6%	N/A	55.8%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		607,160				10,818	6,568,255	1,000,000	6,568,255	3,282,315	0.54	0.50
59	Plant Unit Info	837.0	607,160	97.5%	97.5%	97.5%	10,818			6,568,255	3,282,315	0.54	
60	Turkey Point 4												

FLORIDA POWER & LIGHT COMPANY
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		76,846				11,029	847,530	1,000,000	847,530	423,638	0.55	0.50
2	Plant Unit Info	821.0	76,846	12.6%	12.6%	97.5%	11,029			847,530	423,638	0.55	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		406,984				7,266	2,956,946	1,000,000	2,956,946	11,906,721	2.93	4.03
6	Plant Unit Info	1,248.0	406,984	43.8%	81.1%	58.8%	7,266			2,956,946	11,906,721	2.93	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		150,497				6,609	994,561	1,000,000	994,561	3,946,823	2.62	3.97
10	Plant Unit Info	1,264.0	150,497	13.3%	13.3%	82.7%	6,609			994,561	3,946,823	2.62	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		811,700				6,584	5,344,578	1,000,000	5,344,578	21,219,407	2.61	3.97
14	Plant Unit Info	1,264.0	811,700	86.3%	93.9%	86.3%	6,584			5,344,578	21,219,407	2.61	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		757,386				6,636	5,026,293	1,000,000	5,026,293	19,956,275	2.63	3.97
18	Plant Unit Info	1,247.0	757,386	81.6%	86.4%	81.6%	6,636			5,026,293	19,956,275	2.63	
19	Wildflower PV Solar												
20	Solar		14,604				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	14,604	26.4%	N/A	52.7%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,674	10,531,823				7,379			77,711,920	232,887,934	2.21	
24													
25													
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		12,647				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,647	23.6%	N/A	47.2%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		12,740				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,740	23.8%	N/A	51.8%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		12,469				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,469	23.2%	N/A	50.7%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		714,614				6,623	4,732,638	1,000,000	4,732,638	21,040,755	2.94	4.45
14	Plant Unit Info	1,307.0	714,614	75.9%	93.9%	75.9%	6,623			4,732,638	21,040,755	2.94	
15	Citrus PV Solar												
16	Solar		12,570				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	12,570	23.4%	N/A	46.9%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		12,518				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	12,518	23.3%	N/A	50.9%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		3,261				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	3,261	18.1%	N/A	39.5%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		661,665				7,212	4,772,077	1,000,000	4,772,077	21,212,245	3.21	4.45
26	Plant Unit Info	1,791.0	661,665	51.3%	86.2%	51.3%	7,212			4,772,077	21,212,245	3.21	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	195.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	195.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00
38	Plant Unit Info	213.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		0					0	0	0	0	0.00	0.00
42	Plant Unit Info	213.0	0	0.0%	93.5%	0.0%	0			0	0	0.00	
43	Echo River PV Solar												
44	Solar		13,329				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	13,329	24.9%	N/A	54.2%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		13,313				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	13,313	24.8%	N/A	54.2%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		12,211				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	12,211	22.8%	N/A	49.7%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		12,630				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	12,630	23.6%	N/A	51.4%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		12,427				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	12,427	23.2%	N/A	50.6%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0					0	0	0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		12,426				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	12,426	23.2%	N/A	50.6%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		1,001				10,634	10,645	1,000,000	10,645	47,291	4.72	4.44
7	Plant Unit Info	213.0	1,001	0.7%	94.0%	93.6%	10,634			10,645	47,291	4.72	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		1,001				10,634	10,645	1,000,000	10,645	47,291	4.72	4.44
11	Plant Unit Info	213.0	1,001	0.7%	94.0%	93.6%	10,634			10,645	47,291	4.72	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		12,605				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,605	23.5%	N/A	51.3%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	795.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
31	Manatee 2												
32	Heavy Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	795.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
35	Manatee 3												
36	Gas		134,196				7,428	996,850	1,000,000	996,850	4,402,577	3.28	4.42
37	Plant Unit Info	1,251.0	134,196	14.9%	59.1%	66.6%	7,428			996,850	4,402,577	3.28	
38	Manatee PV Solar												
39	Solar		12,714				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	12,714	23.7%	N/A	47.4%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		5,963				10,939	65,230	1,000,000	65,230	288,087	4.83	4.42
43	Plant Unit Info	489.0	5,963	1.7%	90.6%	60.8%	10,939			65,230	288,087	4.83	
44	Martin 4												
45	Gas		1,748				10,738	18,770	1,000,000	18,770	82,896	4.74	4.42
46	Plant Unit Info	489.0	1,748	0.5%	17.3%	72.0%	10,738			18,770	82,896	4.74	
47	Martin 8 Solar												
48	Solar		6,510				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	6,510	12.1%	N/A	20.7%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		201,355				7,639	1,538,065	1,000,000	1,538,065	6,795,168	3.37	4.42
53	Plant Unit Info	1,246.0	201,355	22.4%	94.0%	70.2%	7,639			1,538,065	6,795,168	3.37	
54	Miami-Dade PV Solar												
55	Solar		13,060				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	13,060	24.4%	N/A	53.1%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,081,292				6,120	6,617,756	1,000,000	6,617,756	29,534,504	2.73	4.46
60	Plant Unit Info	1,638.0	1,081,292	91.7%	96.7%	91.7%	6,120			6,617,756	29,534,504	2.73	

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		12,724				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	12,724	23.7%	N/A	51.8%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		836,125				6,333	5,295,042	1,000,000	5,295,042	23,540,252	2.82	4.45
7	Plant Unit Info	1,251.0	836,125	92.8%	93.9%	92.8%	6,333			5,295,042	23,540,252	2.82	
8	Pioneer Trail PV Solar												
9	Solar		12,057				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,057	22.5%	N/A	49.0%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		449,331				6,654	2,989,944	1,000,000	2,989,944	13,296,137	2.96	4.45
14	Plant Unit Info	1,307.0	449,331	47.7%	57.2%	75.4%	6,654			2,989,944	13,296,137	2.96	
15	Sanford 4												
16	Gas		154,855				7,390	1,144,329	1,000,000	1,144,329	5,083,815	3.28	4.44
17	Plant Unit Info	1,180.0	154,855	18.2%	94.0%	60.8%	7,390			1,144,329	5,083,815	3.28	
18	Sanford 5												
19	Gas		176,282				7,603	1,340,342	1,000,000	1,340,342	5,960,966	3.38	4.45
20	Plant Unit Info	1,180.0	176,282	20.8%	94.0%	60.0%	7,603			1,340,342	5,960,966	3.38	
21	Scherer 4												
22	Coal		178,686				11,410	119,925	17,000,000	2,038,722	5,237,142	2.93	43.67
23	Plant Unit Info	626.0	178,686	39.6%	94.8%	39.6%	11,410			2,038,722	5,237,142	2.93	
24	Southfork PV Solar												
25	Solar		14,045				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,045	26.2%	N/A	57.1%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,255				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,255	17.4%	N/A	34.9%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		704,591				10,328	7,277,022	1,000,000	7,277,022	3,407,851	0.48	0.47
32	Plant Unit Info	1,003.0	704,591	97.5%	97.5%	97.5%	10,328			7,277,022	3,407,851	0.48	
33	St Lucie 2												
34	Nuclear		603,235				10,257	6,187,383	1,000,000	6,187,383	2,717,993	0.45	0.44
35	Plant Unit Info	860.0	603,235	97.5%	97.5%	97.5%	10,257			6,187,383	2,717,993	0.45	
36	ST Project 1 Site 1												
37	Solar		11,706				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	11,706	21.8%	N/A	43.6%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		11,955				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	11,955	22.3%	N/A	48.6%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		12,159				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	12,159	22.7%	N/A	49.5%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		11,832				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	11,832	22.1%	N/A	48.1%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		12,411				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	12,411	23.1%	N/A	50.5%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		12,399				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	12,399	23.1%	N/A	50.4%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		12,629				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	12,629	23.4%	N/A	51.0%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		603,018				10,541	6,356,413	1,000,000	6,356,413	3,176,452	0.53	0.50
59	Plant Unit Info	859.0	603,018	97.5%	97.5%	97.5%	10,541			6,356,413	3,176,452	0.53	
60	Turkey Point 4												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		345,290				10,432	3,602,070	1,000,000	3,602,070	2,219,304	0.64	0.62
2	Plant Unit Info	868.0	345,290	55.3%	55.3%	97.5%	10,432			3,602,070	2,219,304	0.64	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		331,718				7,398	2,453,914	1,000,000	2,453,914	10,901,798	3.29	4.44
6	Plant Unit Info	1,264.0	331,718	36.5%	94.0%	58.6%	7,398			2,453,914	10,901,798	3.29	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		0					0	0	0	0	0.00	0.00
10	Plant Unit Info	1,267.0	0	0.0%	N/A	0.0%	0			0	0	0.00	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		756,008				6,601	4,990,081	1,000,000	4,990,081	22,055,558	2.92	4.42
14	Plant Unit Info	1,267.0	756,008	82.9%	93.9%	82.9%	6,601			4,990,081	22,055,558	2.92	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		729,045				6,720	4,898,884	1,000,000	4,898,884	21,651,799	2.97	4.42
18	Plant Unit Info	1,242.0	729,045	81.5%	93.9%	81.5%	6,720			4,898,884	21,651,799	2.97	
19	Wildflower PV Solar												
20	Solar		13,082				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,082	24.4%	N/A	53.2%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,905	8,996,703				7,485			67,336,822	202,699,881	2.25	
24													
25													
26													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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 - 2020**												
2	Babcock PV Solar												
3	Solar		11,786				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	11,786	21.3%	N/A	46.4%	N/A			N/A	N/A	N/A	
5	Barefoot PV Solar												
6	Solar		11,611				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	11,611	21.0%	N/A	45.7%	N/A			N/A	N/A	N/A	
8	Blue Cypress PV Solar												
9	Solar		11,473				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	11,473	20.7%	N/A	45.2%	N/A			N/A	N/A	N/A	
11	CCEC 3												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		653,930				6,675	4,364,664	1,000,000	4,364,664	20,518,235	3.14	4.70
14	Plant Unit Info	1,307.0	653,930	67.2%	93.9%	67.2%	6,675			4,364,664	20,518,235	3.14	
15	Citrus PV Solar												
16	Solar		11,757				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	11,757	21.2%	N/A	46.3%	N/A			N/A	N/A	N/A	
18	Coral Farms PV Solar												
19	Solar		11,441				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	11,441	20.6%	N/A	45.0%	N/A			N/A	N/A	N/A	
21	Desoto Solar												
22	Solar		2,906				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	25.0	2,906	15.6%	N/A	34.1%	N/A			N/A	N/A	N/A	
24	Fort Myers 2												
25	Gas		627,254				7,311	4,585,964	1,000,000	4,585,964	21,558,564	3.44	4.70
26	Plant Unit Info	1,791.0	627,254	47.1%	94.0%	47.1%	7,311			4,585,964	21,558,564	3.44	
27	Fort Myers 3A												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	195.0	0	0.0%	70.9%	0.0%	0			0	0	0.00	
31	Fort Myers 3B												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	195.0	0	0.0%	70.9%	0.0%	0			0	0	0.00	
35	Fort Myers 3C												
36	Light Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00
38	Plant Unit Info	213.0	0	0.0%	70.9%	0.0%	0			0	0	0.00	
39	Fort Myers 3D												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		0					0	0	0	0	0.00	0.00
42	Plant Unit Info	213.0	0	0.0%	70.9%	0.0%	0			0	0	0.00	
43	Echo River PV Solar												
44	Solar		10,814				N/A	N/A	N/A	N/A	N/A	N/A	N/A
45	Plant Unit Info	74.5	10,814	19.5%	N/A	42.6%	N/A			N/A	N/A	N/A	
46	Hammock PV Solar												
47	Solar		12,233				N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Plant Unit Info	74.5	12,233	22.1%	N/A	48.2%	N/A			N/A	N/A	N/A	
49	Hibiscus PV Solar												
50	Solar		11,247				N/A	N/A	N/A	N/A	N/A	N/A	N/A
51	Plant Unit Info	74.5	11,247	20.3%	N/A	44.3%	N/A			N/A	N/A	N/A	
52	Horizon PV Solar												
53	Solar		11,525				N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	Plant Unit Info	74.5	11,525	20.8%	N/A	45.4%	N/A			N/A	N/A	N/A	
55	Indian River PV Solar												
56	Solar		11,434				N/A	N/A	N/A	N/A	N/A	N/A	N/A
57	Plant Unit Info	74.5	11,434	20.6%	N/A	45.0%	N/A			N/A	N/A	N/A	
58	Indiantown												
59	Coal		0					0	0	0	0	0.00	
60	Plant Unit Info		0	0.0%	N/A	0.0%	0			0	0	0.00	

FLORIDA POWER & LIGHT COMPANY
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Interstate PV Solar												
2	Solar		11,613				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	11,613	21.0%	N/A	45.7%	N/A			N/A	N/A	N/A	
4	Lauderdale 6A												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		0					0	0	0	0	0.00	0.00
7	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
8	Lauderdale 6B												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
12	Lauderdale 6C												
13	Light Oil		0					0	0	0	0	0.00	0.00
14	Gas		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
16	Lauderdale 6D												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
20	Lauderdale 6E												
21	Light Oil		0					0	0	0	0	0.00	0.00
22	Gas		0					0	0	0	0	0.00	0.00
23	Plant Unit Info	213.0	0	0.0%	94.0%	0.0%	0			0	0	0.00	
24	Loggerhead PV Solar												
25	Solar		11,717				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	11,717	21.1%	N/A	46.1%	N/A			N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	795.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
31	Manatee 2												
32	Heavy Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	795.0	0	0.0%	96.2%	0.0%	0			0	0	0.00	
35	Manatee 3												
36	Gas		31,753				8,393	266,491	1,000,000	266,491	1,246,656	3.93	4.68
37	Plant Unit Info	1,251.0	31,753	3.4%	94.1%	57.7%	8,393			266,491	1,246,656	3.93	
38	Manatee PV Solar												
39	Solar		11,751				N/A	N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	11,751	21.2%	N/A	46.3%	N/A			N/A	N/A	N/A	
41	Martin 3												
42	Gas		1,501				11,643	17,476	1,000,000	17,476	81,754	5.45	4.68
43	Plant Unit Info	489.0	1,501	0.4%	74.5%	61.0%	11,643			17,476	81,754	5.45	
44	Martin 4												
45	Gas		1,462				11,664	17,053	1,000,000	17,053	79,773	5.46	4.68
46	Plant Unit Info	489.0	1,462	0.4%	94.0%	59.5%	11,664			17,053	79,773	5.46	
47	Martin 8 Solar												
48	Solar		5,425				N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Plant Unit Info	75.0	5,425	9.7%	N/A	17.9%	N/A			N/A	N/A	N/A	
50	Martin 8												
51	Light Oil		0					0	0	0	0	0.00	0.00
52	Gas		82,843				8,477	702,243	1,000,000	702,243	3,285,120	3.97	4.68
53	Plant Unit Info	1,246.0	82,843	8.9%	94.0%	62.2%	8,477			702,243	3,285,120	3.97	
54	Miami-Dade PV Solar												
55	Solar		12,416				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	12,416	22.4%	N/A	48.9%	N/A			N/A	N/A	N/A	
57	Okeechobee 1												
58	Light Oil		0					0	0	0	0	0.00	0.00
59	Gas		1,078,690				6,128	6,610,197	1,000,000	6,610,197	31,284,056	2.90	4.73
60	Plant Unit Info	1,638.0	1,078,690	88.5%	96.7%	88.5%	6,128			6,610,197	31,284,056	2.90	

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Okeechobee PV Solar												
2	Solar		11,539				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	11,539	20.8%	N/A	45.4%	N/A			N/A	N/A	N/A	
4	PEEC												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		863,341				6,333	5,467,448	1,000,000	5,467,448	25,702,410	2.98	4.70
7	Plant Unit Info	1,251.0	863,341	92.8%	93.9%	92.8%	6,333			5,467,448	25,702,410	2.98	
8	Pioneer Trail PV Solar												
9	Solar		11,176				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	11,176	20.2%	N/A	44.0%	N/A			N/A	N/A	N/A	
11	Riviera 5												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		668,431				6,676	4,462,746	1,000,000	4,462,746	20,979,800	3.14	4.70
14	Plant Unit Info	1,307.0	668,431	68.7%	93.9%	68.7%	6,676			4,462,746	20,979,800	3.14	
15	Sanford 4												
16	Gas		108,735				8,139	885,033	1,000,000	885,033	4,160,530	3.83	4.70
17	Plant Unit Info	1,180.0	108,735	12.4%	94.0%	52.4%	8,139			885,033	4,160,530	3.83	
18	Sanford 5												
19	Gas		106,111				7,974	846,116	1,000,000	846,116	3,977,581	3.75	4.70
20	Plant Unit Info	1,180.0	106,111	12.1%	94.0%	53.2%	7,974			846,116	3,977,581	3.75	
21	Scherer 4												
22	Coal		181,390				11,439	122,051	17,000,000	2,074,863	5,343,980	2.95	43.78
23	Plant Unit Info	626.0	181,390	39.0%	94.8%	39.0%	11,439			2,074,863	5,343,980	2.95	
24	Southfork PV Solar												
25	Solar		12,295				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,295	22.2%	N/A	48.4%	N/A			N/A	N/A	N/A	
27	Space Coast												
28	Solar		1,170				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	10.0	1,170	15.7%	N/A	34.3%	N/A			N/A	N/A	N/A	
30	St Lucie 1												
31	Nuclear		728,079				10,328	7,519,590	1,000,000	7,519,590	3,521,447	0.48	0.47
32	Plant Unit Info	1,003.0	728,079	97.5%	97.5%	97.5%	10,328			7,519,590	3,521,447	0.48	
33	St Lucie 2												
34	Nuclear		623,343				10,257	6,393,629	1,000,000	6,393,629	2,808,593	0.45	0.44
35	Plant Unit Info	860.0	623,343	97.5%	97.5%	97.5%	10,257			6,393,629	2,808,593	0.45	
36	ST Project 1 Site 1												
37	Solar		10,858				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	10,858	19.6%	N/A	42.7%	N/A			N/A	N/A	N/A	
39	ST Project 1 Site 2												
40	Solar		10,920				N/A	N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	10,920	19.7%	N/A	43.0%	N/A			N/A	N/A	N/A	
42	ST Project 1 Site 3												
43	Solar		10,595				N/A	N/A	N/A	N/A	N/A	N/A	N/A
44	Plant Unit Info	74.5	10,595	19.1%	N/A	41.7%	N/A			N/A	N/A	N/A	
45	ST Project 2 Site 1												
46	Solar		10,310				N/A	N/A	N/A	N/A	N/A	N/A	N/A
47	Plant Unit Info	74.5	10,310	18.6%	N/A	40.6%	N/A			N/A	N/A	N/A	
48	ST Project 2 Site 2												
49	Solar		11,337				N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	Plant Unit Info	74.5	11,337	20.5%	N/A	44.6%	N/A			N/A	N/A	N/A	
51	ST Project 2 Site 3												
52	Solar		11,326				N/A	N/A	N/A	N/A	N/A	N/A	N/A
53	Plant Unit Info	74.5	11,326	20.4%	N/A	44.6%	N/A			N/A	N/A	N/A	
54	Sunshine Gateway PV Solar												
55	Solar		10,807				N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	Plant Unit Info	74.5	10,807	19.4%	N/A	42.3%	N/A			N/A	N/A	N/A	
57	Turkey Point 3												
58	Nuclear		623,119				10,541	6,568,293	1,000,000	6,568,293	3,282,334	0.53	0.50
59	Plant Unit Info	859.0	623,119	97.5%	97.5%	97.5%	10,541			6,568,293	3,282,334	0.53	
60	Turkey Point 4												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	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	Nuclear		629,647				10,432	6,568,480	1,000,000	6,568,480	4,046,965	0.64	0.62
2	Plant Unit Info	868.0	629,647	97.5%	97.5%	97.5%	10,432			6,568,480	4,046,965	0.64	
3	Turkey Point 5												
4	Light Oil		0					0	0	0	0	0.00	0.00
5	Gas		181,960				8,182	1,488,728	1,000,000	1,488,728	6,998,494	3.85	4.70
6	Plant Unit Info	1,264.0	181,960	19.4%	94.0%	53.3%	8,182			1,488,728	6,998,494	3.85	
7	WCEC 01												
8	Light Oil		0					0	0	0	0	0.00	0.00
9	Gas		232,558				6,690	1,555,765	1,000,000	1,555,765	7,277,933	3.13	4.68
10	Plant Unit Info	1,267.0	232,558	24.7%	29.4%	74.3%	6,690			1,555,765	7,277,933	3.13	
11	WCEC 02												
12	Light Oil		0					0	0	0	0	0.00	0.00
13	Gas		747,724				6,625	4,953,951	1,000,000	4,953,951	23,174,784	3.10	4.68
14	Plant Unit Info	1,267.0	747,724	79.3%	93.9%	79.3%	6,625			4,953,951	23,174,784	3.10	
15	WCEC 03												
16	Light Oil		0					0	0	0	0	0.00	0.00
17	Gas		702,712				6,720	4,722,172	1,000,000	4,722,172	22,090,512	3.14	4.68
18	Plant Unit Info	1,242.0	702,712	76.1%	93.9%	76.1%	6,720			4,722,172	22,090,512	3.14	
19	Wildflower PV Solar												
20	Solar		11,991				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	11,991	21.6%	N/A	47.2%	N/A			N/A	N/A	N/A	
22	System Totals												
23	Plant Unit Info	29,905	9,170,056				7,641			70,070,902	211,419,521	2.31	
24													
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FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.		Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1	**#6 Heavy Oil (BBLS)**													
2	Purchases													
3	Units	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Unit Cost	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
5	Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Burned													
7	Units	0	0	0	0	0	0	0	6,507	5,879	0	0	0	12,386
8	Unit Cost	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	73.5319	73.5319	0.0000	0.0000	0.0000	73.5319
9	Amount	$0	$0	$0	$0	$0	$0	$0	$478,463	$432,310	$0	$0	$0	$910,773
10	Ending Inventory													
11	Units	767,574	767,574	767,574	767,574	767,574	767,574	767,574	761,067	755,188	755,188	755,188	755,188	755,188
12	Unit Cost	73.5317	73.5317	73.5317	73.5317	73.5317	73.5317	73.5317	73.5323	73.5314	73.5314	73.5314	73.5314	73.5314
13	Amount	$56,441,000	$56,441,000	$56,441,000	$56,441,000	$56,441,000	$56,441,000	$56,441,000	$55,963,000	$55,530,000	$55,530,000	$55,530,000	$55,530,000	$55,530,000
14														
15	**#2 Light Oil (BBLS)**													
16	Purchases													
17	Units	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Unit Cost	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
19	Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	Burned													
21	Units	0	0	0	0	31	0	41	0	0	2	0	0	74
22	Unit Cost	0.0000	0.0000	0.0000	0.0000	94.5239	0.0000	94.5239	0.0000	0.0000	94.5239	0.0000	0.0000	94.5239
23	Amount	$0	$0	$0	$0	$2,951	$0	$3,859	$0	$0	$178	$0	$0	$6,988
24	Ending Inventory													
25	Units	1,340,404	1,340,404	1,340,404	1,340,404	1,340,373	1,340,373	1,340,332	1,340,332	1,340,332	1,340,331	1,340,331	1,340,331	1,340,331
26	Unit Cost	95.8032	95.8032	95.8032	95.8032	95.8032	95.8032	95.8038	95.8038	95.8038	95.8032	95.8032	95.8032	95.8032
27	Amount	$128,415,000	$128,415,000	$128,415,000	$128,415,000	$128,412,000	$128,412,000	$128,409,000	$128,409,000	$128,409,000	$128,408,000	$128,408,000	$128,408,000	$128,408,000
28														
29	**Coal - Scherer (MMBTU)**													
30	Purchases													
31	Units	1,807,038	1,807,038	1,807,038	1,807,038	1,807,038	1,807,038	1,807,038	1,807,038	1,807,038	1,807,038	1,807,038	1,807,038	21,684,459
32	Unit Cost	2.5578	2.5517	2.5390	2.5296	2.5235	2.5395	2.5677	2.5838	2.5777	2.5777	2.5871	2.5937	2.5607
33	Amount	$4,622,000	$4,611,000	$4,588,000	$4,571,000	$4,560,000	$4,589,000	$4,640,000	$4,669,000	$4,658,000	$4,658,000	$4,675,000	$4,687,000	$55,528,000
34	Burned													
35	Units	2,072,358	1,972,709	0	695,018	2,100,191	2,047,679	2,202,108	2,221,874	2,097,104	2,161,833	2,038,722	2,074,863	21,684,459
36	Unit Cost	2.5260	2.5335	0.0000	2.5339	2.5317	2.5333	2.5409	2.5507	2.5571	2.5623	2.5688	2.5756	2.5476
37	Amount	$5,234,753	$4,997,950	$0	$1,761,089	$5,317,088	$5,187,421	$5,595,227	$5,667,262	$5,362,555	$5,539,209	$5,237,142	$5,343,980	$55,243,676
38	Ending Inventory													
39	Units	4,292,823	4,127,153	5,934,191	7,046,211	6,753,058	6,512,418	6,117,348	5,702,512	5,412,446	5,057,652	4,825,968	4,558,143	4,558,143
40	Unit Cost	2.5261	2.5335	2.5351	2.5338	2.5317	2.5333	2.5408	2.5506	2.5571	2.5623	2.5688	2.5756	2.5756
41	Amount	$10,844,000	$10,456,000	$15,044,000	$17,854,000	$17,097,000	$16,498,000	$15,543,000	$14,545,000	$13,840,000	$12,959,000	$12,397,000	$11,740,000	$11,740,000

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.		Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1														
2	**Gas (MCF)**													
3	Burned													
4	Units	41,565,121	39,918,693	46,229,255	48,818,753	51,516,866	55,989,910	61,501,591	62,040,568	56,274,550	54,224,009	41,875,212	40,946,047	600,900,575
5	Unit Cost	4.3854	4.3429	4.1000	3.8315	3.9659	3.8428	3.7975	3.8375	3.8742	4.0077	4.4404	4.6993	4.0556
6	Amount	182,279,507	173,363,235	189,539,454	187,048,319	204,310,674	215,156,770	233,553,886	238,082,034	218,018,237	217,313,972	185,941,139	192,416,202	2,437,023,429
7														
8	**Nuclear (Other)**													
9	Burned													
10	Units	27,049,969	22,623,611	23,326,272	20,453,677	27,046,896	26,174,415	27,046,896	27,046,896	26,174,415	21,326,067	23,422,888	27,049,992	298,741,994
11	Unit Cost	0.5103	0.5117	0.5028	0.4703	0.4767	0.4767	0.4767	0.4767	0.4767	0.4705	0.4919	0.5050	0.4873
12	Amount	13,804,272	11,576,132	11,727,934	9,619,400	12,894,130	12,478,191	12,894,130	12,894,130	12,478,191	10,034,574	11,521,600	13,659,339	145,582,023
13														
14														
15	Note: Totals may not add due to rounding.													

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Month	Sold To	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	Jan - 2020	Off System	OS	453,840	453,840	1.736	3.090	7,880,597	14,024,735	5,037,624
2		St Lucie Reliability Sales		54,224	54,224	0.484	0.484	262,269	262,269	
3	**Total January Estimated**			508,064	508,064	1.603	2.812	8,142,866	14,287,004	5,037,624
4										
5	Feb - 2020	Off System	OS	365,980	365,980	1.782	3.011	6,521,378	11,020,815	3,604,903
6		St Lucie Reliability Sales		50,726	50,726	0.484	0.484	245,348	245,348	
7	**Total February Estimated**			416,706	416,706	1.624	2.704	6,766,726	11,266,163	3,604,903
8										
9	Mar - 2020	Off System	OS	299,770	299,770	1.778	2.809	5,330,382	8,420,322	2,353,195
10		St Lucie Reliability Sales		54,224	54,224	0.484	0.484	262,269	262,269	
11	**Total March Estimated**			353,994	353,994	1.580	2.453	5,592,651	8,682,591	2,353,195
12										
13	Apr - 2020	Off System	OS	174,000	174,000	1.786	2.946	3,108,129	5,125,869	1,566,000
14		St Lucie Reliability Sales		51,294	51,294	0.495	0.495	253,659	253,659	
15	**Total April Estimated**			225,294	225,294	1.492	2.388	3,361,788	5,379,528	1,566,000
16										
17	May - 2020	Off System	OS	146,320	146,320	1.858	3.044	2,717,996	4,454,554	1,338,828
18		St Lucie Reliability Sales		53,003	53,003	0.495	0.495	262,115	262,115	
19	**Total May Estimated**			199,323	199,323	1.495	2.366	2,980,111	4,716,669	1,338,828
20										
21	Jun - 2020	Off System	OS	105,600	105,600	1.858	3.074	1,962,357	3,246,297	992,640
22		St Lucie Reliability Sales		51,294	51,294	0.495	0.495	253,659	253,659	
23	**Total June Estimated**			156,894	156,894	1.412	2.231	2,216,016	3,499,956	992,640
24										
25	YTD-Jun	Off System		1,545,510	1,545,510	1.781	2.995	27,520,839	46,292,592	14,893,190
26		St Lucie Reliability Sales		314,764	314,764	0.489	0.489	1,539,319	1,539,319	
27	**Total 6 Month Period**			1,860,274	1,860,274	1.562	2.571	29,060,158	47,831,912	14,893,190
28										

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Month	Sold To	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	Jul - 2020	Off System	OS	107,260	107,260	1.983	3.199	2,127,136	3,431,554	1,008,244
2		St Lucie Reliability Sales		53,003	53,003	0.495	0.495	262,115	262,115	
3	**Total July Estimated**			160,263	160,263	1.491	2.305	2,389,251	3,693,669	1,008,244
4										
5	Aug - 2020	Off System	OS	83,700	83,700	2.119	3.239	1,773,324	2,711,322	703,080
6		St Lucie Reliability Sales		53,003	53,003	0.495	0.495	262,115	262,115	
7	**Total August Estimated**			136,703	136,703	1.489	2.175	2,035,439	2,973,437	703,080
8										
9	Sep - 2020	Off System	OS	90,000	90,000	2.129	3.423	1,916,517	3,080,757	913,500
10		St Lucie Reliability Sales		51,294	51,294	0.495	0.495	253,659	253,659	
11	**Total September Estimated**			141,294	141,294	1.536	2.360	2,170,176	3,334,416	913,500
12										
13	Oct - 2020	Off System	OS	91,140	91,140	2.055	3.274	1,873,349	2,984,327	865,830
14		St Lucie Reliability Sales		53,003	53,003	0.495	0.495	262,115	262,115	
15	**Total October Estimated**			144,143	144,143	1.481	2.252	2,135,463	3,246,441	865,830
16										
17	Nov - 2020	Off System	OS	193,500	193,500	1.877	2.886	3,632,490	5,584,230	1,470,600
18		St Lucie Reliability Sales		52,475	52,475	0.484	0.484	253,809	253,809	
19	**Total November Estimated**			245,975	245,975	1.580	2.373	3,886,299	5,838,039	1,470,600
20										
21	Dec - 2020	Off System	OS	281,480	281,480	1.879	2.935	5,287,689	8,260,527	2,279,988
22		St Lucie Reliability Sales		54,224	54,224	0.484	0.484	262,269	262,269	
23	**Total December Estimated**			335,704	335,704	1.653	2.539	5,549,957	8,522,795	2,279,988
24										
25	YTD	Off System		2,392,590	2,392,590	1.845	3.024	44,131,343	72,345,309	22,134,432
26		St Lucie Reliability Sales		631,766	631,766	0.490	0.490	3,095,400	3,095,400	
27	**Total 12 Month Period**			3,024,356	3,024,356	1.562	2.494	47,226,744	75,440,709	22,134,432
28										

Note: Totals may not add due to rounding.

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	RAD - Fuel Projection E7 Schedule	Type & Schedule	KWH Purchased (000)	KWH for Firm	Fuel Cost (cents/KWH)	Total $ for Fuel Adj
1	**Jan - 2020**					
2	St Lucie Reliability		55,967	55,967	0.512	286,366
3	SWA		81,093	81,093	2.795	2,266,685
4	**Total Jan - 2020**		137,060	137,060	1.863	2,553,052
5						
6	**Feb - 2020**					
7	St Lucie Reliability		28,886	28,886	0.512	147,802
8	SWA		75,695	75,695	2.860	2,165,091
9	**Total Feb - 2020**		104,581	104,581	2.212	2,312,893
10						
11	**Mar - 2020**					
12	OUC		888	888	3.466	30,774
13	St Lucie Reliability		27,081	27,081	0.451	122,015
14	SWA		78,363	78,363	2.768	2,168,789
15	**Total Mar - 2020**		106,332	106,332	2.183	2,321,578
16						
17	**Apr - 2020**					
18	OUC		1,516	1,516	3.293	49,918
19	St Lucie Reliability		52,928	52,928	0.461	244,031
20	SWA		75,947	75,947	2.789	2,118,134
21	**Total Apr - 2020**		130,391	130,391	1.850	2,412,083
22						
23	**May - 2020**					
24	OUC		540	540	3.302	17,833
25	St Lucie Reliability		54,692	54,692	0.461	252,165
26	SWA		63,776	63,776	2.588	1,650,773
27	**Total May - 2020**		119,008	119,008	1.614	1,920,771
28						
29	**Jun - 2020**					
30	St Lucie Reliability		52,928	52,928	0.461	244,031
31	SWA		78,191	78,191	2.845	2,224,548
32	**Total Jun - 2020**		131,119	131,119	1.883	2,468,579
33						
34	**YTD-Jun - 2020**					
35	OUC		2,944	2,944	3.347	98,525
36	St Lucie Reliability		272,482	272,482	0.476	1,296,410
37	SWA		453,065	453,065	2.780	12,594,020
38	**Total YTD-Jun - 2020**		728,491	728,491	1.920	13,988,955
39						

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	RAD - Fuel Projection E7 Schedule	Type & Schedule	KWH Purchased (000)	KWH for Firm	Fuel Cost (cents/KWH)	Total $ for Fuel Adj
1	**Jul - 2020**					
2	OUC		4,454	4,454	3.405	151,658
3	St Lucie Reliability		54,692	54,692	0.461	252,165
4	SWA		70,070	70,070	2.796	1,959,128
5	**Total Jul - 2020**		129,216	129,216	1.829	2,362,951
6						
7	**Aug - 2020**					
8	OUC		5,815	5,815	3.421	198,905
9	St Lucie Reliability		54,692	54,692	0.461	252,165
10	SWA		70,165	70,165	2.923	2,050,905
11	**Total Aug - 2020**		130,672	130,672	1.915	2,501,975
12						
13	**Sep - 2020**					
14	OUC		3,507	3,507	3.399	119,200
15	St Lucie Reliability		52,928	52,928	0.461	244,031
16	SWA		66,629	66,629	2.801	1,866,043
17	**Total Sep - 2020**		123,064	123,064	1.811	2,229,274
18						
19	**Oct - 2020**					
20	OUC		1,160	1,160	3.407	39,526
21	St Lucie Reliability		54,692	54,692	0.461	252,165
22	SWA		66,568	66,568	3.115	2,073,923
23	**Total Oct - 2020**		122,420	122,420	1.932	2,365,614
24						
25	**Nov - 2020**					
26	OUC		726	726	3.486	25,308
27	St Lucie Reliability		54,162	54,162	0.451	244,031
28	SWA		76,823	76,823	2.969	2,280,970
29	**Total Nov - 2020**		131,711	131,711	1.936	2,550,309
30						
31	**Dec - 2020**					
32	St Lucie Reliability		55,967	55,967	0.451	252,165
33	SWA		65,629	65,629	2.787	1,829,175
34	**Total Dec - 2020**		121,596	121,596	1.712	2,081,340
35						
36	**2020**					
37	OUC		18,606	18,606	3.403	633,122
38	St Lucie Reliability		599,616	599,616	0.466	2,793,132
39	SWA		868,949	868,949	2.837	24,654,165
40	**Total 2020**		1,487,171	1,487,171	1.888	28,080,418
41						
42						
43	Note: Totals may not add due to rounding.					

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	RAD - Fuel Projection E8 Schedule	Type & Schedule	Total KWH Purchased (000)	KWH for Firm (000)	Fuel Cost (cents/KWH)	Total $ for Fuel Adj
1	**Jan - 2020**					
2	Qualifying Facilities		27,900	27,900	1.732	483,244
3	**Total Jan - 2020**		27,900	27,900	1.732	483,244
4						
5	**Feb - 2020**					
6	Qualifying Facilities		21,120	21,120	1.786	377,184
7	**Total Feb - 2020**		21,120	21,120	1.786	377,184
8						
9	**Mar - 2020**					
10	Qualifying Facilities		21,831	21,831	1.682	367,297
11	**Total Mar - 2020**		21,831	21,831	1.682	367,297
12						
13	**Apr - 2020**					
14	Qualifying Facilities		19,942	19,942	1.666	332,150
15	**Total Apr - 2020**		19,942	19,942	1.666	332,150
16						
17	**May - 2020**					
18	Qualifying Facilities		24,845	24,845	1.759	437,131
19	**Total May - 2020**		24,845	24,845	1.759	437,131
20						
21	**Jun - 2020**					
22	Qualifying Facilities		21,768	21,768	1.851	402,842
23	**Total Jun - 2020**		21,768	21,768	1.851	402,842
24						
25	**YTD-Jun - 2020**					
26	Qualifying Facilities		137,406	137,406	1.747	2,399,846
27	**Total YTD-Jun - 2020**		137,406	137,406	1.747	2,399,846
28						
29						
30						

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	RAD - Fuel Projection E8 Schedule	Type & Schedule	Total KWH Purchased (000)	KWH for Firm (000)	Fuel Cost (cents/KWH)	Total $ for Fuel Adj
1	**Jul - 2020**					
2	Qualifying Facilities		16,773	16,773	1.869	313,432
3	**Total Jul - 2020**		16,773	16,773	1.869	313,432
4						
5	**Aug - 2020**					
6	Qualifying Facilities		18,329	18,329	1.900	348,297
7	**Total Aug - 2020**		18,329	18,329	1.900	348,297
8						
9	**Sep - 2020**					
10	Qualifying Facilities		21,524	21,524	1.877	403,932
11	**Total Sep - 2020**		21,524	21,524	1.877	403,932
12						
13	**Oct - 2020**					
14	Qualifying Facilities		30,706	30,706	1.881	577,582
15	**Total Oct - 2020**		30,706	30,706	1.881	577,582
16						
17	**Nov - 2020**					
18	Qualifying Facilities		24,863	24,863	1.799	447,344
19	**Total Nov - 2020**		24,863	24,863	1.799	447,344
20						
21	**Dec - 2020**					
22	Qualifying Facilities		26,412	26,412	1.805	476,813
23	**Total Dec - 2020**		26,412	26,412	1.805	476,813
24						
25	**2020**					
26	Qualifying Facilities		276,013	276,013	1.800	4,967,246
27	**Total 2020**		276,013	276,013	1.800	4,967,246
28						
29						
30	Note: Totals may not add due to rounding.					

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.		Power Sold To / Purchased From	Type & Schedule	Total KWH Purchase (000)	Transaction Cost (cents/KWH)	Total $ for Fuel Adj	Cost if Generated (cents/KWH)	Cost if Generated Col (5) * Col (8)	Fuel Savings ($)
1	Jan - 2020	Economy	OS	1,550	2.100	32,550	2.540	39,370	6,820
2		Total Jan - 2020		1,550	2.100	32,550	2.540	39,370	6,820
3									
4	Feb - 2020	Economy	OS	1,450	2.100	30,450	2.530	36,685	6,235
5		Total Feb - 2020		1,450	2.100	30,450	2.530	36,685	6,235
6									
7	Mar - 2020	Economy	OS	12,400	2.000	248,000	2.619	324,694	76,694
8		Total Mar - 2020		12,400	2.000	248,000	2.619	324,694	76,694
9									
10	Apr - 2020	Economy	OS	32,400	2.200	712,800	2.633	853,200	140,400
11		Total Apr - 2020		32,400	2.200	712,800	2.633	853,200	140,400
12									
13	May - 2020	Economy	OS	82,770	2.350	1,945,095	2.794	2,312,910	367,815
14		Total May - 2020		82,770	2.350	1,945,095	2.794	2,312,910	367,815
15									
16	Jun - 2020	Economy	OS	134,400	2.500	3,360,000	3.124	4,198,800	838,800
17		Total Jun - 2020		134,400	2.500	3,360,000	3.124	4,198,800	838,800
18									
19		**YTD - Jun**							
20		Economy		264,970	2.389	6,328,895	2.931	7,765,659	1,436,764
21		**Total YTD - Jun**		264,970	2.389	6,328,895	2.931	7,765,659	1,436,764

FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.		Power Sold To / Purchased From	Type & Schedule	Total KWH Purchase (000)	Transaction Cost (cents/KWH)	Total $ for Fuel Adj	Cost if Generated (cents/KWH)	Cost if Generated Col (5) * Col (8)	Fuel Savings ($)
1									
2	Jul - 2020	Economy	OS	57,660	2.600	1,499,160	3.187	1,837,565	338,405
3		Total Jul - 2020		57,660	2.600	1,499,160	3.187	1,837,565	338,405
4									
5	Aug - 2020	Economy	OS	82,150	2.600	2,135,900	3.143	2,581,572	445,672
6		Total Aug - 2020		82,150	2.600	2,135,900	3.143	2,581,572	445,672
7									
8	Sep - 2020	Economy	OS	62,100	2.300	1,428,300	2.662	1,653,000	224,700
9		Total Sep - 2020		62,100	2.300	1,428,300	2.662	1,653,000	224,700
10									
11	Oct - 2020	Economy	OS	46,190	2.000	923,800	2.569	1,186,680	262,880
12		Total Oct - 2020		46,190	2.000	923,800	2.569	1,186,680	262,880
13									
14	Nov - 2020	Economy	OS	6,300	1.800	113,400	2.100	132,300	18,900
15		Total Nov - 2020		6,300	1.800	113,400	2.100	132,300	18,900
16									
17	Dec - 2020	Economy	OS	1,860	1.800	33,480	2.300	42,780	9,300
18		Total Dec - 2020		1,860	1.800	33,480	2.300	42,780	9,300
19									
20		**YTD - Dec**		521,230	2.391	12,462,935	2.916	15,199,556	2,736,621
21		**Total YTD - Dec**		521,230	2.391	12,462,935	2.916	15,199,556	2,736,621

Note: Totals may not add due to rounding.

COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	CURRENT SEP 2019	PROPOSED JAN 2020 - APR 2020	DIFFERENCE $	DIFFERENCE %
BASE	$69.46	$69.43	($0.03)	-0.04%
FUEL COST RECOVERY	$22.27	$19.25	-$3.02	-13.56%
ENERGY CONSERVATION COST RECOVERY	$1.50	$1.39	-$0.11	-7.33%
CAPACITY COST RECOVERY	$2.58	$2.30	-$0.28	-10.85%
ENVIRONMENTAL COST RECOVERY	$1.59	$1.55	-$0.04	-2.52%
STORM RESTORATION SURCHARGE	$0.00	$0.00	$0.00	N/A
INTERIM STORM RESTORATION SURCHARGE	$0.00	$0.00	$0.00	N/A
SUBTOTAL	$97.40	$93.92	-$3.48	-3.57%
GROSS RECEIPTS TAX	$2.50	$2.41	-$0.09	-3.60%
TOTAL	**$99.90**	**$96.33**	-$3.57	-3.57%

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

SCHEDULE: H1

Line No.	H1 Schedule	2017	2018	2019	2020	% Diff 2018 to 2017	% Diff 2019 to 2018	% Diff 2020 to 2019
1	**Fuel Cost of System Net Generation ($)**							
2	Heavy Oil	24,618,491	33,336,536	12,853,413	910,773	35.4%	(61.4%)	(92.9%)
3	Light Oil	38,351,438	17,471,205	11,992,197	6,988	(54.4%)	(31.4%)	(99.9%)
4	Coal	124,990,904	70,954,592	69,189,030	55,243,676	(43.2%)	(2.5%)	(20.2%)
5	Gas	2,713,130,934	2,938,221,234	2,493,615,287	2,437,023,429	8.3%	(15.1%)	(2.3%)
6	Nuclear	189,997,758	175,457,637	155,046,037	145,582,023	(7.7%)	(11.6%)	(6.1%)
7	**Sub-Total Fuel Cost of System Net Generation ($)**	3,091,089,526	3,235,441,204	2,742,695,965	2,638,766,889	4.7%	(15.2%)	(3.8%)
8								
9	**System Net Generation (MWh)**							
10	Heavy Oil	183,690	247,838	98,840	6,831	34.9%	(60.1%)	(93.1%)
11	Light Oil	216,136	128,769	140,739	41	(40.4%)	9.3%	(100.0%)
12	Coal	4,163,571	2,583,232	2,368,131	1,901,868	(38.0%)	(8.3%)	(19.7%)
13	Gas	86,710,098	91,213,460	91,020,535	88,597,958	5.2%	(0.2%)	(2.7%)
14	Nuclear	27,970,556	28,176,271	27,708,778	28,212,873	0.7%	(1.7%)	1.8%
15	Solar	645,753	1,835,949	2,546,285	4,160,252	184.3%	38.7%	63.4%
16	**Sub-Total System Net Generation (MWh)**	119,889,804	124,185,520	123,883,308	122,879,823	3.6%	(0.2%)	(0.8%)
17								
18	**Units of Fuel Burned (Unit)**							
19	Heavy Oil	328,531	445,526	175,912	12,386	35.6%	(60.5%)	(93.0%)
20	Light Oil	394,409	188,693	122,023	74	(52.2%)	(35.3%)	(99.9%)
21	Coal	2,564,530	1,717,337	1,599,624	1,275,556	(33.0%)	(6.9%)	(20.3%)
22	Gas	619,984,258	646,603,153	631,370,843	600,900,575	4.3%	(2.4%)	(4.8%)
23	Nuclear	307,203,081	308,786,317	298,655,844	298,741,994	0.5%	(3.3%)	0.0%
24								
25								
26	**BTU Burned (MMBTU)**							
27	Heavy Oil	2,060,902	2,817,296	1,115,625	79,271	36.7%	(60.4%)	(92.9%)
28	Light Oil	2,080,525	1,091,030	706,510	431	(47.6%)	(35.2%)	(99.9%)
29	Coal	45,741,719	28,818,876	27,200,891	21,684,459	(37.0%)	(5.6%)	(20.3%)
30	Gas	633,859,434	660,577,429	637,898,271	600,900,575	4.2%	(3.4%)	(5.8%)
31	Nuclear	307,203,081	308,786,317	298,655,844	298,741,994	0.5%	(3.3%)	0.0%
32	**Sub-Total BTU Burned (MMBTU)**	990,945,661	1,002,090,947	965,577,141	921,406,730	1.1%	(3.6%)	(4.6%)
33								
34	**Generation Mix (%)**							
35	Heavy Oil	0.15%	0.20%	0.08%	0.01%			
36	Light Oil	0.18%	0.10%	0.11%	0.00%			
37	Coal	3.47%	2.08%	1.91%	1.55%			
38	Gas	72.32%	73.45%	73.47%	72.10%			
39	Nuclear	23.33%	22.69%	22.37%	22.96%			
40	Solar	0.54%	1.48%	2.06%	3.39%			
41	**Sub-Total Generation Mix (%)**	100.00%	100.00%	100.00%	100.00%			
42								
43	**Fuel Cost per Unit ($/Unit)**							
44	Heavy Oil	74.9350	74.8252	73.0673	73.5319	(0.1%)	(2.3%)	0.6%
45	Light Oil	97.2377	92.5907	98.2786	94.5239	(4.8%)	6.1%	(3.8%)
46	Coal	48.7383	41.3166	43.2533	43.3095	(15.2%)	4.7%	0.1%
47	Gas	4.3761	4.5441	3.9495	4.0556	3.8%	(13.1%)	2.7%
48	Nuclear	0.6185	0.5682	0.5191	0.4873	(8.1%)	(8.6%)	(6.1%)
49								

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

SCHEDULE: H1

Line No.	H1 Schedule	2017	2018	2019	2020	% Diff 2018 to 2017	% Diff 2019 to 2018	% Diff 2020 to 2019
1	**Fuel Cost per MMBTU ($/MMBTU)**							
2	Heavy Oil	11.9455	11.8328	11.5213	11.4894	(0.9%)	(2.6%)	(0.3%)
3	Light Oil	18.4335	16.0135	16.9739	16.2134	(13.1%)	6.0%	(4.5%)
4	Coal	2.7325	2.4621	2.5436	2.5476	(9.9%)	3.3%	0.2%
5	Gas	4.2803	4.4480	3.9091	4.0556	3.9%	(12.1%)	3.7%
6	Nuclear	0.6185	0.5682	0.5191	0.4873	(8.1%)	(8.6%)	(6.1%)
7	**Sub-Total Fuel Cost per MMBTU ($/MMBTU)**	3.1193	3.2287	2.8405	2.8638	3.5%	(12.0%)	0.8%
8								
9	**BTU Burned per KWH (BTU/KWH)**							
10	Heavy Oil	11,219	11,367	11,287	11,605	1.3%	(0.7%)	2.8%
11	Light Oil	9,626	8,473	5,020	10,591	(12.0%)	(40.8%)	111.0%
12	Coal	10,986	11,156	11,486	11,402	1.5%	3.0%	(0.7%)
13	Gas	7,310	7,242	7,008	6,782	(0.9%)	(3.2%)	(3.2%)
14	Nuclear	10,983	10,959	10,778	10,589	(0.2%)	(1.6%)	(1.8%)
15	**Sub-Total BTU Burned per KWH (BTU/KWH)**	8,265	8,069	7,794	7,498	(2.4%)	(3.4%)	(3.8%)
16								
17	**Generated Fuel Cost per KWH (cents/KWH)**							
18	Heavy Oil	13.4022	13.4509	13.0042	13.3338	0.4%	(3.3%)	2.5%
19	Light Oil	17.7442	13.5678	8.5209	17.1722	(23.5%)	(37.2%)	101.5%
20	Coal	3.0020	2.7467	2.9217	2.9047	(8.5%)	6.4%	(0.6%)
21	Gas	3.1290	3.2213	2.7396	2.7507	2.9%	(15.0%)	0.4%
22	Nuclear	0.6793	0.6227	0.5596	0.5160	(8.3%)	(10.1%)	(7.8%)
23	**Sub-Total Generated Fuel Cost per KWH (cents/KWH)**	2.5783	2.6053	2.2139	2.1474	1.0%	(15.0%)	(3.0%)
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Forty-Sixth Revised Sheet No. 10.101

FLORIDA POWER & LIGHT COMPANY **Cancels Forty-Fifth 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 .0684¢/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:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0112
Secondary Voltage Delivery	1.0275

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)

Issued by: Tiffany Cohen, Director, Rates and Tariffs
Effective:

Fortieth Revised Sheet No. 10.103

FLORIDA POWER & LIGHT COMPANY **Cancels Thirty-Ninth 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:

Equipment Type	Charge
Metering Equipment	0.024%
Distribution Equipment	0.138%
Transmission Equipment	0.078%

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)

Issued by: Tiffany Cohen, Director, Rates and Tariffs
Effective:

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

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: MAY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)
Line No.		Dollars	MWH	Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$2,638,766,889	122,879,823	2.1474
2	Solar Base Rate Adjustment (SoBRA) Fuel Savings - 2020 Project	$11,149,004	122,879,823	0.0091
3	SolarTogether (ST) Credit	$31,975,895		N/A
4	Fuel Cost of Stratified Sales	($23,890,327)	(1,018,036)	2.3467
5	Rail Car Lease (Cedar Bay/Indiantown)	$1,887,737		N/A
6	Adjustments to Fuel Cost	$569,484		N/A
7	TOTAL COST OF GENERATED POWER	$2,660,458,682	121,861,787	2.1832
8	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	28,080,418	1,487,171	1.8882
9	Energy Cost of Economy Purchases (Per E9)	$12,462,935	521,230	2.3911
10	Energy Payments to Qualifying Facilities (Per E8)	$4,967,246	276,013	1.7996
11	TOTAL COST OF PURCHASED POWER	$45,510,599	2,284,414	1.9922
12	TOTAL AVAILABLE MWH (LINE 7 + LINE 11)		124,146,201	
13	Fuel Cost of Economy and Other Power Sales (E6)	($44,131,343)	(2,392,590)	1.8445
14	Gains from Off-System Sales (Per E6)	($22,134,432)		N/A
15	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($3,095,400)	(631,766)	0.4900
16	TOTAL FUEL COST AND GAINS OF POWER SALES	($69,361,175)	(3,024,356)	2.2934
17	Incremental Personnel, Software, and Hardware Costs	$463,695		N/A
18	Variable Power Plant O&M Attributable to Off-System Sales (Per E6)	$1,555,184		N/A
19	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	($338,800)		N/A
20	Total Incremental Optimization Costs	$1,680,079		
21	Total Fuel Costs & Net Power Transactions (Lines 7 + 11 +16 + 20)	$2,638,288,185	121,121,844	2.1782
22	Net Unbilled Sales [1]	$2,187,973	100,448	0.0019
23	Company Use [1]	$2,638,288	121,122	0.0023
24	T & D Losses [1]	$113,446,392	5,208,239	0.0981
25	System MWH Sales (Excluding Stratified Sales)	$2,638,288,185	115,692,035	2.2804
26	Wholesale MWH Sales (Excluding Stratified Sales)	$111,484,033	4,888,711	2.2804
27	Jurisdictional MWH Sales	$2,526,804,152	110,803,324	2.2804
28	Jurisdictional Loss Multiplier	$3,335,381		1.00132
29	Jurisdictional MWH Sales Adjusted for Line Losses	$2,530,139,533	110,803,324	2.2835
30	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	($58,082,532)	110,803,324	(0.0524)
31	TOTAL JURISDICTIONAL FUEL COST	$2,472,057,001	110,803,324	2.2311
32	Revenue Tax Factor	1,779,881		1.00072
33	Fuel Factor Adjusted for Taxes	$2,473,836,882	110,803,324	2.2327
34	GPIF [2]	$8,577,071	110,803,324	0.0077
35	Jurisdictional Incentive Mechanism - FPL Portion	$12,786,460	110,803,324	0.0115
36	Jurisdictionalized Projected Savings	($10,699,682)	78,605,029	(0.0136)
37	Fuel Factor Adjusted for GPIF (Lines 33 through 36)	$2,484,500,731	110,803,324	2.2383
38	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			2.238
39				
40	[1] For informational purposes only			
41	[2] Caluculation based on Jurisdictional KWH sales			
42				
43	Note: Totals may not add due to rounding.			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 21
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-8

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

ESTIMATED FOR THE PERIOD OF: MAY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)
Line No.	CALCULATION OF JURISDICTIONALIZED FUEL SAVINGS	Annual Total
1	SoBRA Fuel Savings Total System	11,149,004
2		
3	Jurisdictional %	95.77438%
4		
5	Jurisdictionalized SoBRA Fuel Savings	10,677,889
6		
7	Jurisdictionalized SoBRA Fuel Savings Adjusted for Losses & Revenue Taxes	10,699,682
8		
9	Note: Totals may not add due to rounding.	

FLORIDA POWER & LIGHT COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: MAY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	GROUPS	RATE SCHEDULE	MAY - DECEMBER		
			Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	A	RS-1 first 1,000 kWh	2.238	1.00212	1.911
2	A	RS-1 all additional kWh	2.238	1.00212	2.911
3					
4	A	GS-1, SL-2, GSCU-1, WIES-1	2.238	1.00212	2.243
5					
6	A-1	SL-1, OL-1, PL-1 [1]	2.171	1.00212	2.176
7					
8	B	GSD-1	2.238	1.00207	2.243
9					
10	C	GSLD-1, CS-1	2.238	1.00157	2.242
11					
12	D	GSLD-2, CS-2, OS-2, MET	2.238	0.99555	2.228
13					
14	E	GSLD-3, CS-3	2.238	0.97529	2.183
15					
16	A	GST-1 On-Peak	2.571	1.00212	2.576
17	A	GST-1 Off-Peak	2.095	1.00212	2.099
18					
19	A	RTR-1 On-Peak			0.333
20		RTR-1 Off-Peak			(0.144)
21					
22	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	2.571	1.00207	2.576
23	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.095	1.00207	2.099
24					
25	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	2.571	1.00157	2.575
26	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.095	1.00157	2.098
27					
28	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	2.571	0.99588	2.560
29	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.095	0.99588	2.086
30					
31	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	2.571	0.97529	2.507
32	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.095	0.97529	2.043
33					
34	F	CILC-1(D), ISST-1(D) On-Peak	2.571	0.99566	2.560
35		CILC-1(D), ISST-1(D) Off-Peak	2.095	0.99566	2.086
36					
37	[1] WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK				
38					
39	Note: Totals may not add due to rounding.				

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ESTIMATED FOR THE PERIOD OF: MAY 2020 THROUGH DECEMBER 2020

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER		
			Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	B	GSD(T)-1 On-Peak	3.071	1.00207	3.077
2		GSD(T)-1 Off-Peak	2.128	1.00207	2.132
3					
4	C	GSLD(T)-1 On-Peak	3.071	1.00157	3.076
5		GSLD(T)-1 Off-Peak	2.128	1.00157	2.131
6					
7	D	GSLD(T)-2 On-Peak	3.071	0.99588	3.058
8		GSLD(T)-2 Off-Peak	2.128	0.99588	2.119
9					
10	Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm				
11	Off Peak Period is defined as all other hours.				
12					
13	Note: All other months served under the otherwise applicable rate schedule.				
14	See Schedule E-1E, Page 1 of 2.				
15					
16	Note: Totals may not add due to rounding.				

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

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: MAY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1	Fuel Cost of System Net Generation (E3)	$201,318,532	$189,937,316	$201,267,387	$198,428,808	$222,524,843	$232,822,382	$252,047,102	$257,121,888	$236,291,294	$232,887,934	$202,699,881	$211,419,521	$2,638,766,889
2	Fuel Cost of Stratified Sales	($593,569)	($1,641,532)	($1,434,388)	($2,480,343)	($928,903)	($2,516,763)	($3,059,438)	($2,924,565)	($2,763,202)	($2,559,521)	($1,938,380)	($1,049,723)	($23,890,327)
3	Rail Car Lease (Cedar Bay/Indiantown)	$157,683	$157,683	$155,772	$157,683	$157,046	$157,683	$157,046	$157,683	$157,683	$157,046	$157,683	$157,046	$1,887,737
4	Solar Base Rate Adjustment (SoBRA) Fuel Savings - 2020 Project	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$929,084	$11,149,004
5	Fuel Cost of Power Sold (Per E6)	($8,142,866)	($6,766,726)	($5,592,651)	($3,361,788)	($2,980,111)	($2,216,016)	($2,389,251)	($2,035,439)	($2,170,176)	($2,135,463)	($3,886,299)	($5,549,957)	($47,226,744)
6	Gains from Off-System Sales (Per E6)	($5,037,624)	($3,604,903)	($2,353,195)	($1,566,000)	($1,338,828)	($992,640)	($1,008,244)	($703,080)	($913,500)	($865,830)	($1,470,600)	($2,279,988)	($22,134,432)
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$2,553,052	$2,312,893	$2,321,578	$2,412,083	$1,920,771	$2,468,579	$2,362,951	$2,501,975	$2,229,274	$2,365,614	$2,550,309	$2,081,340	$28,080,418
8	Energy Payments to Qualifying Facilities (Per A8)	$483,244	$377,184	$367,297	$332,150	$437,131	$402,842	$313,432	$348,297	$403,932	$577,582	$447,344	$476,813	$4,967,246
9	Energy Cost of Economy Purchases (Per E9)	$32,550	$30,450	$248,000	$712,800	$1,945,095	$3,360,000	$1,499,160	$2,135,900	$1,428,300	$923,800	$113,400	$33,480	$12,462,935
10	SolarTogether (ST) Credit	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$31,975,895
11	Total Fuel Costs & Net Power Transactions	$194,364,744	$184,396,107	$198,573,543	$198,229,134	$225,330,785	$237,079,808	$253,516,500	$260,196,400	$238,257,345	$234,944,903	$202,267,080	$208,882,274	$2,636,038,622
12														
13	Incremental Personnel, Software, and Hardware Costs	$42,507	$38,797	$41,981	$40,389	$43,573	$35,498	$37,090	$38,683	$33,906	$38,683	$37,090	$35,498	$463,695
14	Variable Power Plant O&M Attributable to Off-System Sales (Per E6)	$294,996	$237,887	$194,851	$113,100	$95,108	$68,640	$69,719	$54,405	$58,500	$59,241	$125,775	$182,962	$1,555,184
15	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	($1,008)	($943)	($8,060)	($21,060)	($53,801)	($87,360)	($37,479)	($53,398)	($40,365)	($30,024)	($4,095)	($1,209)	($338,800)
16	Total	$336,495	$275,741	$228,772	$132,429	$84,881	$16,778	$69,330	$39,690	$52,041	$67,900	$158,770	$217,251	$1,680,079
17														
18	Other O&M Expense	$28,874	$28,874	$28,874	$30,475	$228,595	$28,874	$173,246	$21,672					$569,484
19														
20	ADJUSTED TOTAL FUEL & NET POWER TRANS	$194,730,113	$184,700,722	$198,831,189	$198,392,038	$225,644,260	$237,125,460	$253,759,076	$260,257,763	$238,309,386	$235,012,803	$202,425,850	$209,099,525	$2,638,288,185
21														
22	System MWH Sales (Excluding Stratified Sales)	8,758,172	7,875,532	8,231,595	8,757,875	9,575,614	10,630,500	11,405,925	11,444,914	11,138,686	10,394,006	8,955,915	8,523,302	115,692,035
23														
24	Cost per KWh	2.2234	2.3452	2.4155	2.2653	2.3564	2.2306	2.2248	2.2740	2.1395	2.2610	2.2602	2.4533	2.2804
25	Jurisdictional Loss Multiplier	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132
26	Jurisdictional Cost	2.2263	2.3483	2.4187	2.2683	2.3596	2.2336	2.2277	2.2770	2.1423	2.2640	2.2632	2.4565	2.2835
27	True Up (cents/KWh)	(.0574)	(.0646)	(.0614)	(.0577)	(.0527)	(.0474)	(.0443)	(.0443)	(.0454)	(.0486)	(.0567)	(.0592)	(.0524)
28	Total (cents/KWh)	2.1689	2.2837	2.3573	2.2106	2.3069	2.1862	2.1834	2.2327	2.0969	2.2154	2.2065	2.3973	2.2311
29	Revenue Tax Factor	.0016	.0016	.0017	.0016	.0017	.0016	.0016	.0016	.0015	.0016	.0016	.0017	.0016
30	Recovery Factor adjusted for Taxes (cents/KWh)	2.1705	2.2853	2.3590	2.2122	2.3086	2.1878	2.1850	2.2343	2.0984	2.2170	2.2081	2.3990	2.2327
31	GPIF (cents/KWh)	.0085	.0095	.0091	.0085	.0078	.0070	.0065	.0065	.0067	.0072	.0084	.0087	.0077
32	Jurisdictional Incentive Mechanism - FPL Portion	.0126	.0142	.0135	.0127	.0116	.0104	.0097	.0097	.0100	.0107	.0125	.0130	.0115
33	Juridictionalized Savings Cents/KWH	-	-	-	-	(.0018)	(.0016)	(.0015)	(.0015)	(.0016)	(.0017)	(.0020)	(.0020)	(.0136)
34	Recovery Factor Including GPIF and Incentive	2.1916	2.3090	2.3816	2.2334	2.3262	2.2036	2.1997	2.2490	2.1135	2.2332	2.2270	2.4187	2.2383
35														
36	Recovery Factor Rounded to .001 (¢/KWh)	2.192	2.309	2.382	2.233	2.326	2.204	2.200	2.249	2.114	2.233	2.227	2.419	2.238
37														

FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION

ESTIMATED FOR THE PERIOD OF: MAY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	39,695,440,896	0.019106	$758,419,490.40	1.911
2	All Additional KWH	19,764,836,314	0.029106	$575,274,527.42	2.911
3	Total KWH	59,460,277,210		$1,333,694,017.82	
4					
5	Avg Fuel Factor	2.238			
6	RS-1 Loss Multiplier	1.00212			
7	Average Fuel Factor	2.243			
8					
9	Target Fuel Revenues	$1,333,694,017.82			

COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	CURRENT SEP 2019	PROPOSED JAN 2020 - APR 2020	DIFFERENCE $	DIFFERENCE %	PROPOSED MAY 2020 - DEC 2020	DIFFERENCE $	DIFFERENCE %
BASE	$69.46	$69.43	($0.03)	-0.04%	$69.94	$0.51	0.73%
FUEL COST RECOVERY	$22.27	$19.25	-$3.02	-13.56%	$19.11	-$0.14	-0.73%
ENERGY CONSERVATION COST RECOVERY	$1.50	$1.39	-$0.11	-7.33%	$1.39	$0.00	0.00%
CAPACITY COST RECOVERY	$2.58	$2.30	-$0.28	-10.85%	$2.30	$0.00	0.00%
ENVIRONMENTAL COST RECOVERY	$1.59	$1.55	-$0.04	-2.52%	$1.55	$0.00	0.00%
STORM RESTORATION SURCHARGE	$0.00	$0.00	$0.00	N/A	$0.00	$0.00	N/A
INTERIM STORM RESTORATION SURCHARGE	$0.00	$0.00	$0.00	N/A	$0.00	$0.00	N/A
SUBTOTAL	$97.40	$93.92	-$3.48	-3.57%	$94.29	$0.37	0.39%
GROSS RECEIPTS TAX	$2.50	$2.41	-$0.09	-3.60%	$2.42	$0.01	0.41%
TOTAL	**$99.90**	**$96.33**	-$3.57	-3.57%	**$96.71**	$0.38	0.39%

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

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)
Line No.		Dollars	MWH	Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$2,638,766,889	122,879,823	2.1474
2	SolarTogether (ST) Credit	$31,975,895		N/A
3	Fuel Cost of Stratified Sales	($23,890,327)	(1,018,036)	2.3467
4	Rail Car Lease (Cedar Bay/Indiantown)	$1,887,737		N/A
5	Adjustments to Fuel Cost	$569,484		N/A
6	TOTAL COST OF GENERATED POWER	$2,649,309,678	121,861,787	2.1740
7	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	28,080,418	1,487,171	1.8882
8	Energy Cost of Economy Purchases (Per E9)	$12,462,935	521,230	2.3911
9	Energy Payments to Qualifying Facilities (Per E8)	$4,967,246	276,013	1.7996
10	TOTAL COST OF PURCHASED POWER	$45,510,599	2,284,414	1.9922
11	TOTAL AVAILABLE MWH (LINE 6 + LINE 10)		124,146,201	
12	Fuel Cost of Economy and Other Power Sales (E6)	($44,131,343)	(2,392,590)	1.8445
13	Gains from Off-System Sales (Per E6)	($22,134,432)		N/A
14	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($3,095,400)	(631,766)	0.4900
15	TOTAL FUEL COST AND GAINS OF POWER SALES	($69,361,175)	(3,024,356)	2.2934
16	Incremental Personnel, Software, and Hardware Costs	$463,695		N/A
17	Variable Power Plant O&M Attributable to Off-System Sales (Per E6)	$1,555,184		N/A
18	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	($338,800)		N/A
19	Total Incremental Optimization Costs	$1,680,079		
20	Total Fuel Costs & Net Power Transactions (Lines 6 + 10 +15 + 19)	$2,627,139,181	121,121,844	2.1690
21	Net Unbilled Sales [1]	$2,178,727	100,448	0.0019
22	Company Use [1]	$2,627,139	121,122	0.0023
23	T & D Losses [1]	$112,966,985	5,208,239	0.0976
24	System MWH Sales (Excluding Stratified Sales)	$2,627,139,181	115,692,035	2.2708
25	Wholesale MWH Sales (Excluding Stratified Sales)	$111,012,919	4,888,711	2.2708
26	Jurisdictional MWH Sales	$2,516,126,262	110,803,324	2.2708
27	Jurisdictional Loss Multiplier	$3,321,287		1.00132
28	Jurisdictional MWH Sales Adjusted for Line Losses	$2,519,447,549	110,803,324	2.2738
29	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	($58,082,532)	110,803,324	(0.0524)
30	TOTAL JURISDICTIONAL FUEL COST	$2,461,365,017	110,803,324	2.2214
31	Revenue Tax Factor	1,772,183		1.00072
32	Fuel Factor Adjusted for Taxes	$2,463,137,200	110,803,324	2.2230
33	GPIF [2]	$8,577,071	110,803,324	0.0077
34	Jurisdictional Incentive Mechanism - FPL Portion	$12,786,460	110,803,324	0.0115
35	Fuel Factor Adjusted for GPIF (Lines 32 through 34)	$2,484,500,731	110,803,324	2.2422
36	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			2.242
37				
38	[1] For informational purposes only			
39	[2] Caluculation based on Jurisdictional KWH sales			
40				
41	Note: Totals may not add due to rounding.			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 22
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-9

FLORIDA POWER & LIGHT COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	GROUPS	RATE SCHEDULE	JANUARY - DECEMBER		
			Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	A	RS-1 first 1,000 kWh	2.242	1.00212	1.915
2	A	RS-1 all additional kWh	2.242	1.00212	2.915
3					
4	A	GS-1, SL-2, GSCU-1, WIES-1	2.242	1.00212	2.247
5					
6	A-1	SL-1, OL-1, PL-1 [1]	2.175	1.00212	2.180
7					
8	B	GSD-1	2.242	1.00207	2.247
9					
10	C	GSLD-1, CS-1	2.242	1.00157	2.246
11					
12	D	GSLD-2, CS-2, OS-2, MET	2.242	0.99555	2.232
13					
14	E	GSLD-3, CS-3	2.242	0.97529	2.187
15					
16	A	GST-1 On-Peak	2.576	1.00212	2.581
17	A	GST-1 Off-Peak	2.099	1.00212	2.103
18					
19	A	RTR-1 On-Peak			0.334
20		RTR-1 Off-Peak			(0.144)
21					
22	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	2.576	1.00207	2.581
23	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.099	1.00207	2.103
24					
25	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	2.576	1.00157	2.580
26	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.099	1.00157	2.102
27					
28	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	2.576	0.99588	2.565
29	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.099	0.99588	2.090
30					
31	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	2.576	0.97529	2.512
32	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.099	0.97529	2.047
33					
34	F	CILC-1(D), ISST-1(D) On-Peak	2.576	0.99566	2.565
35		CILC-1(D), ISST-1(D) Off-Peak	2.099	0.99566	2.090
36					
37	[1] WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK				
38					
39	Note: Totals may not add due to rounding.				

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER		
			Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	B	GSD(T)-1 On-Peak	3.076	1.00207	3.082
2		GSD(T)-1 Off-Peak	2.132	1.00207	2.136
3					
4	C	GSLD(T)-1 On-Peak	3.076	1.00157	3.081
5		GSLD(T)-1 Off-Peak	2.132	1.00157	2.135
6					
7	D	GSLD(T)-2 On-Peak	3.076	0.99588	3.063
8		GSLD(T)-2 Off-Peak	2.132	0.99588	2.123
9					
10	Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm				
11	Off Peak Period is defined as all other hours.				
12					
13	Note: All other months served under the otherwise applicable rate schedule.				
14	See Schedule E-1E, Page 1 of 2.				
15					
16	Note: Totals may not add due to rounding.				

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

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1	Fuel Cost of System Net Generation (E3)	$201,318,532	$189,937,316	$201,267,387	$198,428,808	$222,524,843	$232,822,382	$252,047,102	$257,121,888	$236,291,294	$232,887,934	$202,699,881	$211,419,521	$2,638,766,889
2	Fuel Cost of Stratified Sales	($593,569)	($1,641,532)	($1,434,388)	($2,480,343)	($928,903)	($2,516,763)	($3,059,438)	($2,924,565)	($2,763,202)	($2,559,521)	($1,938,380)	($1,049,723)	($23,890,327)
3	Rail Car Lease (Cedar Bay/Indiantown)	$157,683	$157,683	$155,772	$157,683	$157,046	$157,683	$157,046	$157,683	$157,683	$157,046	$157,683	$157,046	$1,887,737
4	Fuel Cost of Power Sold (Per E6)	($8,142,866)	($6,766,726)	($5,592,651)	($3,361,788)	($2,980,111)	($2,216,016)	($2,389,251)	($2,035,439)	($2,170,176)	($2,135,463)	($3,886,299)	($5,549,957)	($47,226,744)
5	Gains from Off-System Sales (Per E6)	($5,037,624)	($3,604,903)	($2,353,195)	($1,566,000)	($1,338,828)	($992,640)	($1,008,244)	($703,080)	($913,500)	($865,830)	($1,470,600)	($2,279,988)	($22,134,432)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$2,553,052	$2,312,893	$2,321,578	$2,412,083	$1,920,771	$2,468,579	$2,362,951	$2,501,975	$2,229,274	$2,365,614	$2,550,309	$2,081,340	$28,080,418
7	Energy Payments to Qualifying Facilities (Per E8)	$483,244	$377,184	$367,297	$332,150	$437,131	$402,842	$313,432	$348,297	$403,932	$577,582	$447,344	$476,813	$4,967,246
8	Energy Cost of Economy Purchases (Per E9)	$32,550	$30,450	$248,000	$712,800	$1,945,095	$3,360,000	$1,499,160	$2,135,900	$1,428,300	$923,800	$113,400	$33,480	$12,462,935
9	SolarTogether (ST) Credit	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$2,664,658	$31,975,895
10	Total Fuel Costs & Net Power Transactions	$193,435,660	$183,467,023	$197,644,459	$197,300,050	$224,401,701	$236,150,724	$252,587,416	$259,267,317	$237,328,262	$234,015,819	$201,337,996	$207,953,190	$2,624,889,618
11														
12	Incremental Personnel, Software, and Hardware Costs	$42,507	$38,797	$41,981	$40,389	$43,573	$35,498	$37,090	$38,683	$33,906	$38,683	$37,090	$35,498	$463,695
13	Variable Power Plant O&M Attributable to Off-System Sales (Per E6)	$294,996	$237,887	$194,851	$113,100	$95,108	$68,640	$69,719	$54,405	$58,500	$59,241	$125,775	$182,962	$1,555,184
14	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	($1,008)	($943)	($8,060)	($21,060)	($53,801)	($87,360)	($37,479)	($53,398)	($40,365)	($30,024)	($4,095)	($1,209)	($338,800)
15	Total	$336,495	$275,741	$228,772	$132,429	$84,881	$16,778	$69,330	$39,690	$52,041	$67,900	$158,770	$217,251	$1,680,079
16														
17	Other O&M Expense	$28,874	$28,874	$28,874	$30,475	$228,595	$28,874	$173,246	$21,672					$569,484
18														
19	ADJUSTED TOTAL FUEL & NET POWER TRANS	$193,801,029	$183,771,638	$197,902,105	$197,462,954	$224,715,177	$236,196,376	$252,829,993	$259,328,679	$237,380,303	$234,083,720	$201,496,767	$208,170,441	$2,627,139,181
20														
21	System MWH Sales (Excluding Stratified Sales)	8,758,172	7,875,532	8,231,595	8,757,875	9,575,614	10,630,500	11,405,925	11,444,914	11,138,686	10,394,006	8,955,915	8,523,302	115,692,035
22														
23	Cost per KWh	2.2128	2.3335	2.4042	2.2547	2.3467	2.2219	2.2167	2.2659	2.1311	2.2521	2.2499	2.4424	2.2708
24	Jurisdictional Loss Multiplier	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132	1.00132
25	Jurisdictional Cost	2.2157	2.3365	2.4074	2.2577	2.3498	2.2248	2.2196	2.2689	2.1339	2.2551	2.2528	2.4456	2.2738
26	True Up (cents/KWh)	(.0574)	(.0646)	(.0614)	(.0577)	(.0527)	(.0474)	(.0443)	(.0443)	(.0454)	(.0486)	(.0567)	(.0592)	(.0524)
27	Total (cents/KWh)	2.1583	2.2719	2.3460	2.2000	2.2971	2.1774	2.1753	2.2246	2.0885	2.2065	2.1961	2.3864	2.2214
28	Revenue Tax Factor	.0016	.0016	.0017	.0016	.0017	.0016	.0016	.0016	.0015	.0016	.0016	.0017	.0016
29	Recovery Factor adjusted for Taxes (cents/KWh)	2.1599	2.2735	2.3477	2.2016	2.2988	2.1790	2.1769	2.2262	2.0900	2.2081	2.1977	2.3881	2.2230
30	GPIF (cents/KWh)	.0085	.0095	.0091	.0085	.0078	.0070	.0065	.0065	.0067	.0072	.0084	.0087	.0077
31	Jurisdictional Incentive Mechanism - FPL Portion	.0126	.0142	.0135	.0127	.0116	.0104	.0097	.0097	.0100	.0107	.0125	.0130	.0115
32	Recovery Factor Including GPIF and Incentive	2.1810	2.2972	2.3703	2.2228	2.3182	2.1964	2.1931	2.2424	2.1067	2.2260	2.2186	2.4098	2.2422
33														
34	Recovery Factor Rounded to .001 (¢/KWh)	2.181	2.297	2.370	2.223	2.318	2.196	2.193	2.242	2.107	2.226	2.219	2.410	2.242
35														

FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	39,695,440,896	0.019146	$760,007,308.03	1.915
2	All Additional KWH	19,764,836,314	0.029146	$576,065,120.88	2.915
3	Total KWH	59,460,277,210		$1,336,072,428.91	
4					
5	Avg Fuel Factor	2.242			
6	RS-1 Loss Multiplier	1.00212			
7	Average Fuel Factor	2.247			
8					
9	Target Fuel Revenues	$1,336,072,428.91			

COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	CURRENT SEP 2019	PROPOSED JAN 2020 - APR 2020	DIFFERENCE $	DIFFERENCE %	PROPOSED MAY 2020 - DEC 2020	DIFFERENCE $	DIFFERENCE %
BASE	$69.46	$69.43	($0.03)	-0.04%	$69.94	$0.51	0.73%
FUEL COST RECOVERY	$22.27	$19.15	-$3.12	-14.01%	$19.15	$0.00	0.00%
ENERGY CONSERVATION COST RECOVERY	$1.50	$1.39	-$0.11	-7.33%	$1.39	$0.00	0.00%
CAPACITY COST RECOVERY	$2.58	$2.30	-$0.28	-10.85%	$2.30	$0.00	0.00%
ENVIRONMENTAL COST RECOVERY	$1.59	$1.55	-$0.04	-2.52%	$1.55	$0.00	0.00%
STORM RESTORATION SURCHARGE	$0.00	$0.00	$0.00	N/A	$0.00	$0.00	N/A
INTERIM STORM RESTORATION SURCHARGE	$0.00	$0.00	$0.00	N/A	$0.00	$0.00	N/A
SUBTOTAL	$97.40	$93.82	-$3.58	-3.68%	$94.33	$0.51	0.54%
GROSS RECEIPTS TAX	$2.50	$2.41	-$0.09	-3.60%	$2.42	$0.01	0.41%
TOTAL	**$99.90**	**$96.23**	-$3.67	-3.67%	**$96.75**	$0.52	0.54%

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY COSTS
ESTIMATED 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.	Strata	Line	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	Payments to Non-cogenerators	$2,039,420	$2,039,420	$2,039,420	$2,039,420	$2,367,800	$2,412,200	$2,412,200	$2,412,200	$2,412,200	$2,193,280	$2,193,280	$2,193,280	$26,754,120
2		Payments to Co-generators	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$1,430,100
3		Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$9,426,736	$9,395,461	$9,364,185	$9,332,910	$9,301,635	$9,270,359	$9,239,084	$9,207,808	$9,176,533	$9,145,257	$9,113,982	$9,082,706	$111,056,656
4		Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($85,241)	($84,831)	($84,422)	($84,012)	($83,603)	($83,193)	($82,783)	($82,374)	($81,964)	($81,554)	($81,145)	($80,735)	($995,858)
5		Indiantown Transaction - Regulatory Asset - Amortization and Return	$6,192,152	$6,164,018	$6,135,884	$6,107,749	$6,079,615	$6,051,481	$6,023,347	$5,995,212	$5,967,078	$5,938,944	$5,910,810	$5,882,676	$72,448,966
6		SJRPP Transaction Revenue Requirements	$866,014	$854,238	$842,461	$830,685	$818,908	$807,132	$795,355	$783,579	$771,803	$760,026	$748,250	$736,473	$9,614,923
7		Incremental Plant Security Costs O&M	$2,595,620	$2,469,286	$2,851,243	$2,612,823	$2,331,784	$2,575,911	$2,746,599	$2,315,535	$2,305,630	$2,850,875	$2,425,088	$1,942,933	$30,023,326
8		Incremental Plant Security Costs Capital	$358,237	$361,140	$365,205	$368,852	$371,729	$375,171	$379,873	$385,015	$389,345	$393,021	$393,790	$408,293	$4,549,672
9		Incremental Nuclear NRC Compliance Costs O&M	$84,402	$82,893	$84,231	$84,231	$83,713	$84,231	$84,749	$83,713	$84,231	$84,231	$83,713	$85,749	$1,010,084
10		Incremental Nuclear NRC Compliance Costs Capital	$1,137,098	$1,142,173	$1,152,477	$1,158,844	$1,171,160	$1,179,833	$1,176,690	$1,174,099	$1,179,007	$1,187,684	$1,192,432	$1,201,841	$14,053,337
11		Transmission of Electricity by Others	$136,152	$54,897	$44,966	$26,100					$13,500	$13,671	$38,700	$70,370	$398,356
12		Transmission Revenues from Capacity Sales	($1,106,514)	($894,534)	($736,746)	($451,740)	($397,730)	($291,300)	($296,174)	($234,918)	($250,740)	($245,148)	($481,140)	($692,850)	($6,079,534)
13		Sub-Total Base	$21,763,250	$21,703,334	$22,178,079	$22,145,036	$22,164,186	$22,500,999	$22,598,114	$22,159,045	$22,085,797	$22,359,462	$21,656,935	$20,949,911	$264,264,148
14															
15	General	Incremental Plant Security Costs O&M	$11,433	$9,942	$11,264	$11,264	$10,752	$11,264	$11,776	$10,752	$11,264	$11,264	$10,752	$11,776	$133,505
16		Incremental Plant Security Costs Capital	$2,599	$2,583	$2,567	$2,550	$2,534	$2,518	$2,502	$2,485	$2,469	$2,453	$2,436	$2,312	$30,009
17		Sub-Total General	$14,033	$12,525	$13,831	$13,815	$13,286	$13,782	$14,278	$13,237	$13,733	$13,717	$13,189	$14,089	$163,514
18															
19	Intermediate	Incremental Plant Security Costs O&M	$75,182	$69,148	$74,188	$274,132	$352,566	$310,733	$164,727	$72,566	$73,992	$74,412	$72,426	$75,979	$1,690,054
20		Incremental Plant Security Costs Capital	$45,911	$45,809	$45,707	$45,605	$45,503	$45,401	$45,299	$45,197	$45,095	$44,993	$44,891	$44,789	$544,196
21		Sub-Total Intermediate	$121,093	$114,957	$119,895	$319,737	$398,069	$356,134	$210,026	$117,763	$119,087	$119,405	$117,317	$120,767	$2,234,250
22															
23	Peaking	Incremental Plant Security Costs O&M	$42,583	$40,463	$42,249	$42,192	$41,900	$42,192	$42,919	$41,900	$42,046	$42,482	$41,755	$42,774	$505,455
24		Incremental Plant Security Costs Capital	$6,464	$6,444	$6,425	$6,405	$6,385	$6,366	$6,346	$6,326	$6,306	$6,287	$6,267	$6,247	$76,269
25		Sub-Total Peaking	$49,047	$46,907	$48,674	$48,597	$48,286	$48,557	$49,265	$48,226	$48,353	$48,769	$48,022	$49,021	$581,724
26															
27	Solar	Incremental Plant Security Costs O&M	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$4,167	$50,000
28		Incremental Plant Security Costs Capital	$37,117	$44,190	$44,102	$48,779	$53,446	$53,339	$53,232	$53,126	$53,019	$55,294	$57,565	$62,213	$615,422
29		Sub-Total Solar	$41,284	$48,357	$48,269	$52,945	$57,612	$57,506	$57,399	$57,292	$57,185	$59,461	$61,732	$66,380	$665,422
30															
31		Total	$21,988,707	$21,926,081	$22,408,748	$22,580,129	$22,681,439	$22,976,978	$22,929,082	$22,395,564	$22,324,155	$22,600,813	$21,897,193	$21,200,167	$267,909,057
32															
33	Totals may not add due to rounding														

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 23
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: R. B. Deaton RBD-10

Docket No. 20190001-EI
Appendix V - 2020 CCR Projections
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE

ESTIMATED 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	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1	Total Capacity Costs	21,988,707	21,926,081	22,408,748	22,580,129	22,681,439	22,976,978	22,929,082	22,395,564	22,324,155	22,600,813	21,897,193	21,200,167	267,909,057
2														
3	Total Base Capacity Costs	21,763,250	21,703,334	22,178,079	22,145,036	22,164,186	22,500,999	22,598,114	22,159,045	22,085,797	22,359,462	21,656,935	20,949,911	264,264,148
4	Base Jurisdictional Factor	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	
5	Total Base Jurisdictionalized Capacity Costs	20,847,502	20,790,107	21,244,876	21,213,223	21,231,567	21,554,208	21,647,237	21,226,643	21,156,477	21,418,626	20,745,660	20,068,386	253,144,513
6														
7	Total Intermediate Capacity Costs	121,093	114,957	119,895	319,737	398,069	356,134	210,026	117,763	119,087	119,405	117,317	120,767	2,234,250
8	Intermediate Jurisdictional Factor	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	
9	Total Intermediate Jurisdictionalized Capacity Costs	114,017	108,240	112,889	301,054	374,809	335,325	197,754	110,882	112,129	112,428	110,462	113,710	2,103,699
10														
11	Total Peaking Capacity Costs	49,047	46,907	48,674	48,597	48,286	48,557	49,265	48,226	48,353	48,769	48,022	49,021	581,724
12	Peaking Jurisdictional Factor	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	
13	Total Peaking Jurisdictionalized Capacity Costs	46,617	44,583	46,263	46,189	45,893	46,151	46,824	45,837	45,957	46,353	45,643	46,592	552,903
14														
15	Total Solar Capacity Costs	41,284	48,357	48,269	52,945	57,612	57,506	57,399	57,292	57,185	59,461	61,732	66,380	665,422
16	Solar Jurisdictional Factor	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	
17	Total Solar Jurisdictionalized Capacity Costs	39,547	46,322	46,238	50,718	55,188	55,086	54,984	54,881	54,779	56,959	59,134	63,587	637,423
18														
19	Total Transmission Capacity Costs													
20	Transmission Jurisdictional Factor	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	
21	Total Transmission Jurisdictionalized Capacity Costs													
22														
23	Total General Capacity Costs	14,033	12,525	13,831	13,815	13,286	13,782	14,278	13,237	13,733	13,717	13,189	14,089	163,514
24	General Jurisdictional Factor	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	
25	Total General Jurisdictionalized Capacity Costs	13,599	12,138	13,404	13,388	12,876	13,356	13,837	12,829	13,309	13,293	12,781	13,654	158,465
26														
27	Jurisdictionalized Capacity Costs	21,061,282	21,001,391	21,463,670	21,624,572	21,720,334	22,004,127	21,960,636	21,451,072	21,382,651	21,647,659	20,973,680	20,305,929	256,597,002
28														
29														
30	Net Jurisdictionalized CCR Costs	21,061,282	21,001,391	21,463,670	21,624,572	21,720,334	22,004,127	21,960,636	21,451,072	21,382,651	21,647,659	20,973,680	20,305,929	256,597,002
31														
32	FINAL TRUE-UP -- (Over)/Under Recovery													($7,161,719)
33	ACT/EST TRUE-UP -- (Over)/Under Recovery													($9,002,615)
34	2017 SoBRA True-up													($6,657,982)
35	Total (Lines 30 + 32 + 33 + 34)													233,774,686
36	Revenue Tax Multiplier													1.00072
37	Total Recoverable Capacity Costs													233,943,004
38														
39														
40	Totals may not add due to rounding													

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Appendix V - 2020 CCR Projections
Exhibit RBD-10, Page 2 of 32

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY DEMAND ALLOCATION % BY RATE CLASS
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Rate Class Summary - Non-Fuel	AVG 12CP Load Factor at Meter (%) [a]	Projected Sales at Meter (kwh) [b]	Projected AVG 12CP at Meter (kW) [c]	Demand Loss Expansion Factor [d]	Energy Loss Expansion Factor [e]	Projected Sales at Generation (kwh) [f]	Projected AVG 12CP at Generation (kW) [e]	Percentage of Sales at Generation (%) [h]	Percentage of Demand at Generation (%) [i]
1	RS1/RTR1	62.589%	59,460,277,210	10,844,890	1.05968205	1.04536835	62,157,891,785	11,492,136	53.70564%	57.76011%
2	GS1/GST1	63.937%	6,318,956,205	1,128,210	1.05968205	1.04536835	6,605,636,812	1,195,544	5.70740%	6.00887%
3	GSD1/GSDT1/HLFT1	72.046%	27,177,649,229	4,306,235	1.05961769	1.04531916	28,409,317,428	4,562,963	24.54621%	22.93370%
4	OS2	166.456%	11,404,137	782	1.03776783	1.02880687	11,732,654	812	0.01014%	0.00408%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2	72.350%	9,978,343,665	1,574,402	1.05887368	1.04479831	10,425,356,551	1,667,093	9.00771%	8.37890%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	86.886%	2,567,503,407	337,333	1.05102316	1.03886422	2,667,287,415	354,544	2.30459%	1.78196%
7	GSLD3/GSLDT3/CS3/CST3	82.905%	312,336,004	43,007	1.02272339	1.01738204	317,765,040	43,984	0.27456%	0.22107%
8	SST1T	102.028%	83,436,125	9,335	1.02272339	1.01738204	84,886,415	9,547	0.07334%	0.04799%
9	SST1D1/SST1D2/SST1D3	59.719%	2,044,616	391	1.04075563	1.03005290	2,106,063	407	0.00182%	0.00204%
10	CILC D/CILC G	87.093%	2,684,992,306	351,929	1.05097974	1.03888173	2,789,389,451	369,870	2.41009%	1.85899%
11	CILC T	93.902%	1,372,501,622	166,852	1.02272339	1.01738204	1,396,358,496	170,644	1.20648%	0.85767%
12	MET	78.120%	80,453,173	11,756	1.03776783	1.02880687	82,770,777	12,200	0.07152%	0.06132%
13	OL1/SL1/SL1M/PL1	12,054.711%	625,271,399	592	1.05968205	1.04536835	653,638,930	627	0.56476%	0.00315%
14	SL2/SL2M/GSCU1	97.212%	128,154,944	15,049	1.05968205	1.04536835	133,969,122	15,947	0.11575%	0.08015%
15										
16	Total		110,803,324,042	18,790,763			115,738,106,939	19,896,318	100.00000%	100.00000%
17										
18	[a] Calculated: Col(4)/8760 hours / Col(5)									
19	[b] Projected kwh sales for the period January 2020 through December 2020.									
20	[c] AVG 12 CP load factor based on 2016-2018 load research data and 2020 projections.									
21	[d] Based on 2020 demand losses.									
22	[e] Based on 2020 energy losses.									
23	[f] Col(4) * Col(7)									
24	[g] Col(5) * Col(6)									
25	[h] Col(8) / Total for Col(8)									
26	[i] Col(9) / Total for Col(9)									
27										
28	Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin									
29	taking service on these schedules during the period, they will be billed using the applicable SST1 factor.									
30										
31	Totals may not add due to rounding.									

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	RATE SCHEDULE	Percentage of Sales at Generation (%) [a]	Percentage of Demand at Generation (%) [b]	Energy Related Cost ($) [c]	Demand Related Cost ($) [d]	Total Capacity Costs ($) [e]	Projected Sales at Meter (kwh) [f]	Billing KW Load Factor (%) [g]	Projected Billed KW at Meter (KW) [h]	Capacity Recovery Factor ($/KW) [i]	Capacity Recovery Factor ($/kwh) [j]	RDC ($/KW) [k]	SDD ($/KW) [l]
1	RS1/RTR1	53.70564%	57.76011%	9,664,661	124,731,454	134,396,115	59,460,277,210			-	0.00226	-	-
2	GS1/GST1	5.70740%	6.00887%	1,027,082	12,975,999	14,003,081	6,318,956,205			-	0.00222	-	-
3	GSD1/GSDT1/HLFT1	24.54621%	22.93370%	4,417,241	49,524,735	53,941,976	27,177,649,229	51.30483%	72,565,597	0.74	-	-	-
4	OS2	0.01014%	0.00408%	1,824	8,809	10,633	11,404,137			-	0.00093	-	-
5	GSLD1/GSLDT1/CS1/CST1/HLFT2	9.00771%	8.37890%	1,620,993	18,094,016	19,715,010	9,978,343,665	58.43225%	23,392,843	0.84	-	-	-
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	2.30459%	1.78196%	414,725	3,848,095	4,262,820	2,567,503,407	65.78614%	5,346,305	0.80	-	-	-
7	GSLD3/GSLDT3/CS3/CST3	0.27456%	0.22107%	49,408	477,388	526,796	312,336,004	67.48470%	634,007	0.83	-	-	-
8	SST1T	0.07334%	0.04799%	13,199	103,625	116,823	83,436,125	19.21029%	594,973	-	-	0.10	0.05
9	SST1D1/SST1D2/SST1D3	0.00182%	0.00204%	327	4,415	4,742	2,044,616	19.97912%	14,019	-	-	0.10	0.05
10	CILC D/CILC G	2.41009%	1.85899%	433,710	4,014,432	4,448,142	2,684,992,306	71.17771%	5,167,448	0.86	-	-	-
11	CILC T	1.20648%	0.85767%	217,114	1,852,106	2,069,220	1,372,501,622	75.43684%	2,492,336	0.83	-	-	-
12	MET	0.07152%	0.06132%	12,870	132,419	145,289	80,453,173	56.46258%	195,191	0.74	-	-	-
13	OL1/SL1/SL1M/PL1	0.56476%	0.00315%	101,631	6,810	108,442	625,271,399			-	0.00017	-	-
14	SL2/SL2M/GSCU1	0.11575%	0.08015%	20,830	173,085	193,916	128,154,944			-	0.00151	-	-
15	TOTAL			17,995,616	215,947,388	233,943,004							

16

17 [a] Obtained from Page 3, Col(10)

18 [b] Obtained from Page 3, Col(11)

19 [c] (Total Capacity Costs/13) * Col(3)

20 [d] (Total Capacity Costs/13 * 12) * Col(4)

21 [e] Col(3) + Col(4)

22 [f] Projected kwh sales for the period January 2020 through December 2020.

23 [g] (kWh sales / 8760 hours)/(avg customer NCP)

24 [h] Col(8) / (Col(9) *730)

25 [i] Col(7) / Col(10)

26 [j] Col(7) / Col(8)

27 [k] RDC = Reservation Demand Charge - (Total Col 7)/(Page 3 Total Col 5)(.10)(Page x Col 5)/12 Months

28 [l] SDD = Sum of Daily Demand Charge - (Total Col 7)/(Page 3 Total Col 5)/(21 onpeak days)(Page 3 Col 6)/12 Months

29

30 Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin

31 taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

32

33 Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - BASE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
ESTIMATED 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															
2		**INVESTMENTS**														
3		Expenditures/Additions		$436,485	$671,502	$781,537	$547,440	$552,615	$715,433	$927,110	$846,262	$685,554	$652,051	$595,511	($14,931,107)	($7,519,607)
4		Clearings to Plant													$15,535,484	$15,535,484
5		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	($313,513)	($313,513)
6		Other														
7																
8		Plant-In-Service/Depreciation Base	$30,243,670	$30,243,670	$30,243,670	$30,243,670	$30,243,670	$30,243,670	$30,243,670	$30,243,670	$30,243,670	$30,243,670	$30,243,670	$30,243,670	$45,779,155	
9		Less: Accumulated Depreciation	$2,899,580	$3,022,135	$3,144,691	$3,267,246	$3,389,802	$3,512,357	$3,634,913	$3,757,468	$3,880,024	$4,002,579	$4,125,135	$4,245,078	$4,376,331	
10		CWIP - Non Interest Bearing	$7,519,608	$7,956,093	$8,627,595	$9,409,131	$9,956,571	$10,509,187	$11,224,620	$12,151,730	$12,997,992	$13,683,546	$14,335,597	$14,931,108	$1	
11																
12		Net Investment (Lines 8 - 9 + 10)	$34,863,699	$35,177,628	$35,726,574	$36,385,556	$36,810,440	$37,240,500	$37,833,377	$38,637,932	$39,361,638	$39,924,637	$40,454,132	$40,929,700	$41,402,824	
13																
14		Average Net Investment		35,020,663	35,452,101	36,056,065	36,597,998	37,025,470	37,536,939	38,235,655	38,999,785	39,643,137	40,189,384	40,691,916	41,166,262	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes [a]		196,262	198,680	202,065	205,102	207,497	210,364	214,279	218,562	222,167	225,229	228,045	230,703	2,558,954
18		b. Debt Component (Line 14 x debt rate x 1/12) [b]		39,419	39,905	40,585	41,195	41,676	42,252	43,038	43,898	44,622	45,237	45,803	46,337	513,966
19																
20		Investment Expenses														
21		a. Depreciation		122,555	122,556	122,555	122,556	122,555	122,556	122,555	122,556	122,555	122,556	119,943	131,253	1,476,751
22		b. Amortization														
23		c. Other														
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		358,237	361,140	365,205	368,852	371,729	375,171	379,873	385,015	389,345	393,021	393,790	408,293	4,549,672
26																
27																
28																
29																

30 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [b] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - INTERMEDIATE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
ESTIMATED 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															
2		**INVESTMENTS**														
3		Expenditures/Additions														
4		Clearings to Plant														
5		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Other														
7																
8		Plant-In-Service/Depreciation Base	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	
9		Less: Accumulated Depreciation	$764,038	$779,198	$794,358	$809,518	$824,678	$839,838	$854,997	$870,157	$885,317	$900,477	$915,637	$930,797	$945,957	
10		CWIP - Non Interest Bearing														
11																
12		Net Investment (Lines 8 - 9 + 10)	$4,576,946	$4,561,786	$4,546,626	$4,531,467	$4,516,307	$4,501,147	$4,485,987	$4,470,827	$4,455,667	$4,440,507	$4,425,347	$4,410,187	$4,395,027	
13																
14		Average Net Investment		4,569,366	4,554,206	4,539,046	4,523,887	4,508,727	4,493,567	4,478,407	4,463,247	4,448,087	4,432,927	4,417,767	4,402,607	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes [(a)]		25,608	25,523	25,438	25,353	25,268	25,183	25,098	25,013	24,928	24,843	24,758	24,673	301,683
18		b. Debt Component (Line 14 x debt rate x 1/12) [(b)]		5,143	5,126	5,109	5,092	5,075	5,058	5,041	5,024	5,007	4,990	4,973	4,956	60,593
19																
20		Investment Expenses														
21		a. Depreciation		15,160	15,160	15,160	15,160	15,160	15,160	15,160	15,160	15,160	15,160	15,160	15,160	181,919
22		b. Amortization														
23		c. Other														
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		45,911	45,809	45,707	45,605	45,503	45,401	45,299	45,197	45,095	44,993	44,891	44,789	544,196
26																
27																
28																
29																

30 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [(b)] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - GENERAL
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
ESTIMATED 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															
2		**INVESTMENTS**														
3		Expenditures/Additions														
4		Clearings to Plant														
5		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	($12,959)	($12,959)
6		Other														
7																
8		Plant-In-Service/Depreciation Base	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	
9		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	$146,581	
10		CWIP - Non Interest Bearing														
11																
12		Net Investment (Lines 8 - 9 + 10)	$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)	
13																
14		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)	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes [a]		148	135	121	107	94	80	67	53	40	26	12	(1)	883
18		b. Debt Component (Line 14 x debt rate x 1/12) [b]		30	27	24	22	19	16	13	11	8	5	3	(0)	177
19																
20		Investment Expenses														
21		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
22		b. Amortization														
23		c. Other														
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		2,599	2,583	2,567	2,550	2,534	2,518	2,502	2,485	2,469	2,453	2,436	2,312	30,009
26																
27																
28																
29																

30 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [b] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - PEAKING
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
ESTIMATED 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															
2		**INVESTMENTS**														
3		Expenditures/Additions														
4		Clearings to Plant														
5		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Other														
7																
8		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	
9		Less: Accumulated Depreciation	$146,041	$148,970	$151,899	$154,828	$157,758	$160,687	$163,616	$166,545	$169,474	$172,403	$175,333	$178,262	$181,191	
10		CWIP - Non Interest Bearing														
11																
12		Net Investment (Lines 8 - 9 + 10)	$526,742	$523,813	$520,884	$517,955	$515,025	$512,096	$509,167	$506,238	$503,309	$500,380	$497,450	$494,521	$491,592	
13																
14		Average Net Investment		525,278	522,348	519,419	516,490	513,561	510,632	507,702	504,773	501,844	498,915	495,986	493,057	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes [a]		2,944	2,927	2,911	2,895	2,878	2,862	2,845	2,829	2,812	2,796	2,780	2,763	34,242
18		b. Debt Component (Line 14 x debt rate x 1/12) [b]		591	588	585	581	578	575	571	568	565	562	558	555	6,877
19																
20		Investment Expenses														
21		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
22		b. Amortization														
23		c. Other														
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		6,464	6,444	6,425	6,405	6,385	6,366	6,346	6,326	6,306	6,287	6,267	6,247	76,269
26																
27																
28																
29																

30 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [b] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY - SOLAR
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
ESTIMATED 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															
2		**INVESTMENTS**														
3		Expenditures/Additions														
4		Clearings to Plant		$1,500,000			$1,000,000						$500,000		$1,000,000	$4,000,000
5		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Other														
7																
8		Plant-In-Service/Depreciation Base	$3,148,455	$4,648,455	$4,648,455	$4,648,455	$5,648,455	$5,648,455	$5,648,455	$5,648,455	$5,648,455	$5,648,455	$6,148,455	$6,148,455	$7,148,455	
9		Less: Accumulated Depreciation	$4,421	$15,369	$28,424	$41,478	$55,937	$71,799	$87,662	$103,525	$119,388	$135,250	$151,815	$169,082	$187,753	
10		CWIP - Non Interest Bearing														
11																
12		Net Investment (Lines 8 - 9 + 10)	$3,144,034	$4,633,086	$4,620,031	$4,606,977	$5,592,518	$5,576,656	$5,560,793	$5,544,930	$5,529,067	$5,513,205	$5,996,640	$5,979,373	$6,960,702	
13																
14		Average Net Investment		3,888,560	4,626,559	4,613,504	5,099,748	5,584,587	5,568,724	5,552,861	5,536,999	5,521,136	5,754,922	5,988,006	6,470,037	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes [(a)]		21,792	25,928	25,855	28,580	31,297	31,208	31,119	31,030	30,941	32,252	33,558	36,259	359,820
18		b. Debt Component (Line 14 x debt rate x 1/12) [(b)]		4,377	5,208	5,193	5,740	6,286	6,268	6,250	6,232	6,215	6,478	6,740	7,283	72,270
19																
20		Investment Expenses														
21		a. Depreciation		10,948	13,054	13,054	14,459	15,863	15,863	15,863	15,863	15,863	16,565	17,267	18,671	183,332
22		b. Amortization														
23		c. Other														
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		37,117	44,190	44,102	48,779	53,446	53,339	53,232	53,126	53,019	55,294	57,565	62,213	
26																
27																
28																
29																

30 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [(b)] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 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
ESTIMATED 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															
2		**INVESTMENTS**														
3		Expenditures/Additions		$163,940	$2,228,675	$635,612	$1,061,267	($4,737,715)			$163,940	$2,228,676	$1,283,833	$1,061,268	($4,737,717)	($648,221)
4		Clearings to Plant				$648,221		$5,000,026							$5,000,028	$10,648,275
5		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Other														
7																
8		Plant-In-Service/Depreciation Base	$116,485,903	$116,485,903	$116,485,903	$117,134,124	$117,134,124	$122,134,150	$122,134,150	$122,134,150	$122,134,150	$122,134,150	$122,134,150	$122,134,150	$127,134,178	
9		Less: Accumulated Depreciation	$13,747,098	$14,189,361	$14,631,624	$15,075,353	$15,520,549	$15,976,640	$16,443,628	$16,910,616	$17,377,603	$17,844,591	$18,311,579	$18,778,566	$19,253,679	
10		CWIP - Non Interest Bearing	$648,221	$812,161	$3,040,837	$3,676,449	$4,737,716	$0	$0	$0	$163,941	$2,392,616	$3,676,449	$4,737,717	$0	
11																
12		Net Investment (Lines 8 - 9 + 10)	$103,387,026	$103,108,703	$104,895,116	$105,735,220	$106,351,291	$106,157,510	$105,690,522	$105,223,535	$104,920,488	$106,682,176	$107,499,021	$108,093,301	$107,880,499	
13																
14		Average Net Investment		103,247,864	104,001,910	105,315,168	106,043,255	106,254,400	105,924,016	105,457,029	105,072,011	105,801,332	107,090,598	107,796,161	107,986,900	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes [a]		578,620	582,845	590,205	594,285	595,469	593,617	591,000	588,842	592,930	600,155	604,109	605,178	7,117,255
18		b. Debt Component (Line 14 x debt rate x 1/12) [b]		116,216	117,065	118,543	119,362	119,600	119,228	118,702	118,269	119,090	120,541	121,335	121,550	1,429,501
19																
20		Investment Expenses														
21		a. Depreciation		442,263	442,263	443,729	445,196	456,092	466,988	466,988	466,988	466,988	466,988	466,988	475,113	5,506,580
22		b. Amortization														
23		c. Other														
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		1,137,098	1,142,173	1,152,477	1,158,844	1,171,160	1,179,833	1,176,690	1,174,099	1,179,007	1,187,684	1,192,432	1,201,841	14,053,337
26																
27																
28																
29																

30 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [b] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 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
ESTIMATED 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															
2	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	
3															
4	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
5															
6	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	
7															
8	Average Unamortized Regulatory Asset - Loss of PPA	$281,162,978	$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	
9															
10	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	
11															
12	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
13															
14	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	
15															
16	Return on Unamortized Regulatory Asset - Loss of PPA only														
17	Equity Component [a]		$1,156,886	$1,137,443	$1,117,999	$1,098,556	$1,079,112	$1,059,669	$1,040,225	$1,020,782	$1,001,338	$981,895	$962,452	$943,008	$12,599,366
18															
19	Equity Comp. grossed up for taxes [a]		$1,549,643	$1,523,599	$1,497,554	$1,471,510	$1,445,466	$1,419,421	$1,393,377	$1,367,332	$1,341,288	$1,315,243	$1,289,199	$1,263,155	$16,876,787
20															
21	Debt Component (Line 4 * debt rate / 12) [b]		$311,246	$306,015	$300,784	$295,553	$290,322	$285,091	$279,860	$274,629	$269,398	$264,167	$258,936	$253,705	$3,389,705
22															
23	Total Return Requirements (Line 19 + 21)		$1,860,889	$1,829,614	$1,798,338	$1,767,063	$1,735,788	$1,704,512	$1,673,237	$1,641,961	$1,610,686	$1,579,410	$1,548,135	$1,516,859	$20,266,492
24	Total Recoverable Costs (Line 4 + 12 + 23)		$9,426,736	$9,395,461	$9,364,185	$9,332,910	$9,301,635	$9,270,359	$9,239,084	$9,207,808	$9,176,533	$9,145,257	$9,113,982	$9,082,706	111,056,656
25															
26															
27															

28 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

29 [b] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

30

31 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CEDAR BAY TRANSACTION
REGULATORY LIABILITY - BOOK/TAX DIFFERENCE ASSOCIATED TO PLANT ASSET
ESTIMATED 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															
2	Regulatory Liability - Book/Tax Timing Difference		($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)	
3															
4	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
5															
6	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)	
7															
8	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)	
9															
10	Return on Unamortized Regulatory Asset - Loss of PPA only														
11	Equity Component		($15,152)	($14,898)	($14,643)	($14,388)	($14,134)	($13,879)	($13,624)	($13,370)	($13,115)	($12,860)	($12,606)	($12,351)	($165,021)
12															
13	Equity Comp. grossed up for taxes [(a)]		($20,297)	($19,955)	($19,614)	($19,273)	($18,932)	($18,591)	($18,250)	($17,909)	($17,568)	($17,227)	($16,885)	($16,544)	($221,045)
14															
15	Debt Component (Line 8 * debt rate / 12) [(b)]		($4,077)	($4,008)	($3,940)	($3,871)	($3,803)	($3,734)	($3,665)	($3,597)	($3,528)	($3,460)	($3,391)	($3,323)	($44,397)
16															
17	Total Return Requirements (Line 13 + 15)		($24,373)	($23,963)	($23,554)	($23,144)	($22,735)	($22,325)	($21,915)	($21,506)	($21,096)	($20,686)	($20,277)	($19,867)	($265,442)
18	Total Recoverable Costs (Line 4 + 17)		($85,241)	($84,831)	($84,422)	($84,012)	($83,603)	($83,193)	($82,783)	($82,374)	($81,964)	($81,554)	($81,145)	($80,735)	$464,974
19															
20															
21															

22 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

23 [(b)] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

24

25 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
ESTIMATED 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															
2	Regulatory Asset Loss of PPA [c]		$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															
4	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
5															
6	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	
7															
8	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	
9															
10	Return on Unamortized Regulatory Asset - Loss of PPA only														
11	Equity Component		$1,250,578	$1,233,088	$1,215,597	$1,198,107	$1,180,616	$1,163,125	$1,145,635	$1,128,144	$1,110,654	$1,093,163	$1,075,672	$1,058,182	$13,852,562
12															
13	Equity Comp. grossed up for taxes [a]		$1,675,144	$1,651,715	$1,628,286	$1,604,858	$1,581,429	$1,558,001	$1,534,572	$1,511,144	$1,487,715	$1,464,286	$1,440,858	$1,417,429	$18,555,437
14															
15	Debt Component (Line 4 * debt rate / 12) [b]		$336,453	$331,747	$327,042	$322,336	$317,630	$312,925	$308,219	$303,513	$298,808	$294,102	$289,396	$284,691	$3,726,862
16															
17	Total Return Requirements (Line 13 + 15)		$2,011,596	$1,983,462	$1,955,328	$1,927,194	$1,899,060	$1,870,925	$1,842,791	$1,814,657	$1,786,523	$1,758,388	$1,730,254	$1,702,120	$22,282,299
18	Total Recoverable Costs (Line 4 + 17)		$6,192,152	$6,164,018	$6,135,884	$6,107,749	$6,079,615	$6,051,481	$6,023,347	$5,995,212	$5,967,078	$5,938,944	$5,910,810	$5,882,676	$72,448,966
19															
20															
21															

22 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

23 [b] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

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

25

26 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SJRPP TRANSACTION
REGULATORY ASSETS AND LIABILITIES RELATED TO SJRPP TRANSACTION
ESTIMATED 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 [c]		$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 Amortization		$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$23,582,609
3	Unamortized Regulatory Asset - SJRPP Transaction Shutdown Payment	$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)	($4,306,345)	($4,091,028)	($3,875,711)	($3,660,394)	($3,445,076)	($3,229,759)	($3,014,442)	($2,799,124)	($2,583,807)	($2,368,490)	
6	Other regulatory liability - SJRPP Suspension Liability Amortization (Refund)		($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($2,583,807)
7	Unamortized Regulatory Liability - SJRPP Suspension Liability	($4,736,980)	($4,521,663)	($4,306,345)	($4,091,028)	($3,875,711)	($3,660,394)	($3,445,076)	($3,229,759)	($3,014,442)	($2,799,124)	($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	$32,373,153	$30,623,253	$28,873,352	$27,123,452	$25,373,552	$23,623,652	$21,873,752	$20,123,852	$18,373,952	
10															
11	Equity Component		$157,406	$150,085	$142,764	$135,443	$128,122	$120,800	$113,479	$106,158	$98,837	$91,515	$84,194	$76,873	$1,405,677
12	Equity Comp. grossed up for taxes [a]		$210,845	$201,038	$191,232	$181,425	$171,618	$161,811	$152,005	$142,198	$132,391	$122,584	$112,778	$102,971	$1,882,897
13	Debt Component (Line 9 x debt rate x 1/12) [b]		$42,348	$40,379	$38,409	$36,439	$34,470	$32,500	$30,530	$28,560	$26,591	$24,621	$22,651	$20,682	$378,180
14															
15	Total Return Requirements (Line 12 + 13)		$253,193	$241,417	$229,641	$217,864	$206,088	$194,311	$182,535	$170,758	$158,982	$147,206	$135,429	$123,653	$2,261,077
16															
17	Other SJRPP Transaction Items [d]														
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 + 12 + 13 + 18 + 19)		$866,014	$854,238	$842,461	$830,685	$818,908	$807,132	$795,355	$783,579	$771,803	$760,026	$748,250	$736,473	$9,614,923
22															

23 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

24 [b] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

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

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

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
Schedule E12 - Capacity Costs
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2020 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

2020 Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
BS-NEG '91	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$1,430,100
Total	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$1,430,100

Florida Power & Light Company
Schedule E12 - Capacity Costs
Page 2 of 2

2020 Projection

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
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	Orlando Utilities Commission PPA	Other Entity	January 1, 2019	December 31, 2020

2020 Capacity in MW

Contract	January	February	March	April	May	June	July	August	September	October	November	December
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

Contract	January	February	March	April	May	June	July	August	September	October	November	December
1												
2												
3												
Total	$2,288,953	$2,288,953	$2,288,953	$2,288,953	$2,617,333	2,661,733	$2,661,733	$2,661,733	$2,661,733	$2,442,813	$2,442,813	$2,442,813

Total Capacity Payments to Non-Cogenerators for 2020 (1) (2)	26,754,120

(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.

(2) Appendix V, page 1, line 1

FLORIDA POWER & LIGHT COMPANY
BASED ON RATE CASE ALLOCATION OF INDIANTOWN REVENUE REQUIREMENT
JANUARY 2020 THROUGH DECEMBER 2020
12CP & 1/13th COS Allocation Method

		Rate	12 CP & 1/13 Weighted Avg Demand (MW)[1]	Allocation	2019 Indiantown Revenue Requirement Allocation
		(1)	(2)	(3)	(4)
1	RS1/RTR1		11,510	58.7%	$2,163,081
2	GS1/GST1/WIES1		1,100	5.6%	$206,800
3	GSD1/GSDT1/HLFT1		4,277	21.8%	$803,733
4	OS2		1	0.0%	$266
5	GSLD1/GSLDT1/CS1/CST1/HLFT2		1,728	8.8%	$324,714
6	GSLD2/GSLDT2/CS2/CST2/HLFT3		344	1.8%	$64,734
7	GSLD3/GSLDT3/CS3/CST3		24	0.1%	$4,466
8	SST1T		10	0.1%	$1,856
9	SST1D1/SST1D2/SST1D3		2	0.0%	$333
10	CILC D/CILC G		383	2.0%	$72,034
11	CILC T		196	1.0%	$36,876
12	MET		15	0.1%	$2,788
13	OL1/SL1/PL1/SL-1M		19	0.1%	$3,580
14	SL2, GSCU1, SL2M		13	0.1%	$2,519
15	Total		19,623	100.0%	**$3,687,779**

Notes:
[1] From MFR E-9 Column 11 "12 CP & 1/13 Weighted Avg Demand (MW) for 2020

FLORIDA POWER & LIGHT COMPANY

CALCULATION OF CAPACITY RECOVERY FACTOR FOR INDIANTOWN

JANUARY 2020 THROUGH DECEMBER 2020

12CP & 1/13th COS Allocation Method

	Rate Schedule	(1) Projected Sales at Meter (kWh)	(2) Billing kW Load Factor (%)	(3) Projected Billed kW at Meter (kW)	(4) Total Capacity Costs ($)	(5) Capacity Recovery Factor ($/kW)	(6) Capacity Recovery Factor ($/kWh)
1	RS1/RTR1	59,460,277,210	-		$2,163,081		0.00004
2	GS1/GST1/WIES1	6,318,956,205	-		$206,800		0.00003
3	GSD1/GSDT1/HLFT1	27,177,649,229	51.30483%	72,565,597	$803,733	0.01	
4	OS2	11,404,137	-		$266		0.00002
5	GSLD1/GSLDT1/CS1/CST1/HLFT2	9,978,343,665	58.43225%	23,392,843	$324,714	0.01	
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,567,503,407	65.78614%	5,346,305	$64,734	0.01	
7	GSLD3/GSLDT3/CS3/CST3	312,336,004	67.48470%	634,007	$4,466	0.01	
8	SST1T	83,436,125	19.21029%	594,973	$1,856		
9	SST1D1/SST1D2/SST1D3	2,044,616	19.97912%	14,019	$333		
10	CILC D/CILC G	2,684,992,306	71.17771%	5,167,448	$72,034	0.01	
11	CILC T	1,372,501,622	75.43684%	2,492,336	$36,876	0.01	
12	MET	80,453,173	56.46258%	195,191	$2,788	0.01	
13	OL1/SL1/PL1/SL-1M	625,271,399	-		$3,580		0.00001
14	SL2, GSCU1, SL2M	128,154,944	-		$2,519		0.00002
		110,803,324,042		110,402,719	**$3,687,779**		

(1) Projected kWh sales for the period January 2020 through December 2020
(2) Billing kW load factor based on 2014-2016 load research data and 2020 projections
(3) Calculated: Col (1) / (730 hours * Col (2))
(4) Per rate case allocation worksheet
(5) Calculated: Col (4) / Col (3)
(6) Calculated: Col (4) / Col (1)

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 4)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 4)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

CAPACITY RECOVERY FACTORS

	RDD ** ($/kw)	DDC ** ($/kw)
ISST1D	$0.00	$0.00
ISST1T	$0.00	$0.00
SST1T	$0.00	$0.00
SST1D1/SST1D2/SST1D3	$0.00	$0.00

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPATCITY PAYMENT RECOVERY FACTOR
INCLUDING INDIANTOWN REVENUE REQUIREMENTS
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	RAD - CCR ICL Factors	Jan 2020 - Dec 2020 Capacity Recovery Factor				2020 Indiantown Capacity Recovery Factor		Total Jan 2020 - Dec 2020 Capacity Recovery Factor			
		Capacity Recovery Factor ($/KW)	Capacity Recovery Factor ($/kwh)	RDC ($/KW)	SDD ($/KW)	Capacity Recovery Factor ($/KW)	Capacity Recovery Factor ($/kwh)	Capacity Recovery Factor ($/KW)	Capacity Recovery Factor ($/kwh)	RDC ($/KW)	SDD ($/KW)
1	RS1/RTR1	-	0.00226	-	-	-	0.00004	-	0.00230	-	-
2	GS1/GST1	-	0.00222	-	-	-	0.00003	-	0.00225	-	-
3	GSD1/GSDT1/HLFT1	0.74	-	-	-	0.01	-	0.75	-	-	-
4	OS2	-	0.00093	-	-	-	0.00002	-	0.00095	-	-
5	GSLD1/GSLDT1/CS1/CST1/HLFT2	0.84	-	-	-	0.01	-	0.85	-	-	-
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	0.80	-	-	-	0.01	-	0.81	-	-	-
7	GSLD3/GSLDT3/CS3/CST3	0.83	-	-	-	0.01	-	0.84	-	-	-
8	SST1T	-	-	0.10	0.05	-	-	-	-	0.10	0.05
9	SST1D1/SST1D2/SST1D3	-	-	0.10	0.05	-	-	-	-	0.10	0.05
10	CILC D/CILC G	0.86	-	-	-	0.01	-	0.87	-	-	-
11	CILC T	0.83	-	-	-	0.01	-	0.84	-	-	-
12	MET	0.74	-	-	-	0.01	-	0.75	-	-	-
13	OL1/SL1/SL1M/PL1	-	0.00017	-	-	-	0.00001	-	0.00018	-	-
14	SL2/SL2M/GSCU1	-	0.00151	-	-	-	0.00002	-	0.00153	-	-

INDIANTOWN SUBSIDIARY
2020 REVENUE REQUIREMENTS

Line No.	Revenue Requirement Calculation	2020
1		
2		
3	**Jurisdictional Adjusted Rate Base**	**$11,847,451**
4		
5	**Rate of Return on Rate Base**	**6.371%**
6		
7	**Required Jurisdictional Net Operating Income**	**754,842**
8		
9	**Jurisdictional Adjusted Net Operating Income (Loss)**	**(1,994,471)**
10		
11	**Net Operating Income Deficiency (Excess)**	**2,749,314**
12		
13	**Net Operating Income Multiplier** [(1)]	**1.34135**
14		
15	**Revenue Requirement**	**$3,687,779**
16		
17		
18		
19		
20		
21		
22		
23	**Notes:**	
24	(1) Represents the 2018 NOI multiplier provided on Page 13 of Exhibit KO-20 in	
25	Docket No. 20160021-EI revised with new federal tax rates for the Tax Cuts and Jobs Act enacted in 2017 and effective in 2018.	

INDIANTOWN SUBSIDIARY
2020 REVENUE REQUIREMENTS

Line No.	Capital Structure [1]	Jurisdictional Adjusted	Ratio	Cost Rate	Wtd Cost Rate
1	Long Term Debt	$ 10,490,880,245	28.12%	4.44%	1.25%
2	Short Term Debt	669,988,433	1.80%	3.62%	0.06%
3	Preferred Stock	-	0.00%	0.00%	0.00%
4	Common Equity	17,554,936,062	47.05%	10.55%	4.96%
5	Customer Deposits	403,097,747	1.08%	2.11%	0.02%
6	Deferred Income Taxes	7,870,776,333	21.10%	0.00%	0.00%
7	Investment Tax Credits	319,453,350	0.86%	8.26%	0.07%
8	**TOTAL**	$ 37,309,132,171	100.00%		6.37%

	Rate Base - 13-Month Average	Per Book	Sep Factor [4]	Jurisdictional
13	Plant In Service[2]	$ 8,500,000	95.21%	$ 8,093,182
14	Working Capital[3]	3,903,007	96.19%	3,754,269
15	Total	$ 12,403,007		$ 11,847,451

	Net Operating Income	Per Book	Sep Factor[4]	Jurisdictional
20	Operations and Maintenance Expense [5]	$ 2,200,000	95.34%	$ 2,097,374
21	Property Insurance [6]	5,000	96.32%	4,816
22	Property Taxes	590,000	96.51%	569,395
23	Income Taxes	(708,393)		(677,113)
24	Total NOI	$ (2,086,607)		$ (1,994,471)

Notes:

[1] Amounts reflected are from FPL's May 2019 ESR.

[2] Represents land.

[3] Represents projected working capital for 2020.

[4] Based on FPL's most recent cost of service calculations prepared for the 2019 budget cycle.

[5] Excludes amounts associated with fuel cost recovery and regulatory asset related to the Indiantown Transaction approved in Docket No. 20160154-EI.

[6] Represents liability insurance associated with PPA revenue. FPL is retaining most of the risk to insure the facility.

2020 PROJECTED SEPARATION FACTORS

CLAUSES

	SUMMARY
DEMAND	
FPL101 - Transmission	0.899387
FPL102 - Non-Stratified Production	0.957922
FPL103INT - Intermediate Strata Production	0.941569
FPL103PEAK - Peaking Strata Production	0.950455
ENERGY	
FPL201 - Total Sales	0.950640
FPL202 - Non-Stratified Sales	0.958799
FPL203INT - Intermediate Strata Sales	0.942430
FPL203PEAK - Peaking Strata Sales	0.951325
GENERAL PLANT	
I900 - LABOR	0.969124

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
FPL101 - TRANSMISSION: 12CP Demand
December 2020 - PROJECTED

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	338,117	0.0000	0.4124	0.5876	1.0227	1.0378	1.0597	0	144,722	210,518	355,240	1.6058%	1.7855%
CILC-1G	13,812	0.0000	0.0216	0.9784	1.0227	1.0378	1.0597	0	310	14,320	14,630	0.0661%	0.0735%
CILC-1T	166,852	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	170,644	0	0	170,644	0.7714%	0.8577%
GS(T)-1	1,128,210	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	1,195,544	1,195,544	5.4043%	6.0089%
GSCU-1	11,416	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	12,097	12,097	0.0547%	0.0608%
GSD(T)-1	4,306,235	0.0000	0.0029	0.9971	1.0227	1.0378	1.0597	0	13,125	4,549,837	4,562,963	20.6263%	22.9337%
GSLD(T)-1	1,574,402	0.0000	0.0369	0.9631	1.0227	1.0378	1.0597	0	60,270	1,606,823	1,667,093	7.5359%	8.3789%
GSLD(T)-2	337,333	0.0000	0.3951	0.6049	1.0227	1.0378	1.0597	0	138,323	216,221	354,544	1.6027%	1.7820%
GSLD(T)-3	43,007	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	43,984	0	0	43,984	0.1988%	0.2211%
MET	11,756	0.0000	1.0000	0.0000	1.0227	1.0378	1.0597	0	12,200	0	12,200	0.0552%	0.0613%
OL-1	79	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	84	84	0.0004%	0.0004%
OS-2	782	0.0000	1.0000	0.0000	1.0227	1.0378	1.0597	0	812	0	812	0.0037%	0.0041%
RS(T)-1	10,844,890	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	11,492,136	11,492,136	51.9487%	57.7601%
SL-1	446	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	473	473	0.0021%	0.0024%
SL-1M	67	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	70	70	0.0003%	0.0004%
SL-2	3,546	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	3,758	3,758	0.0170%	0.0189%
SL-2M	87	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	92	92	0.0004%	0.0005%
SST-DST	391	0.0000	0.8637	0.1363	1.0227	1.0378	1.0597	0	350	56	407	0.0018%	0.0020%
SST-TST	9,335	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	9,547	0	0	9,547	0.0432%	0.0480%
TOTAL RETAIL	18,790,763							224,175	370,113	19,302,030	19,896,318	89.9387%	100.0000%
FKEC	124,145	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	126,966	0	0	126,966	0.5739%	
FPUC (INT)	13,177	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	13,476	0	0	13,476	0.0609%	
FPUC (PEAK)	14,405	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	14,733	0	0	14,733	0.0666%	
HOMESTEAD (INT)	4,400	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	4,500	0	0	4,500	0.0203%	
LCEC	717,529	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	733,834	0	0	733,834	3.3172%	
MOORE HAVEN	570	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	583	0	0	583	0.0026%	
NEW SMRYNA BCH	7,333	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	7,500	0	0	7,500	0.0339%	
NEW SMYRNA BCH (INT)	4,889	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	5,000	0	0	5,000	0.0226%	
NEW SMRYNA BCH (PEAK)	8,963	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	9,167	0	0	9,167	0.0414%	
QUINCY	3,096	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	3,167	0	0	3,167	0.0143%	
SEMINOLE (INT)	195,556	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	200,000	0	0	200,000	0.9041%	
WAUCHULA	1,874	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	1,917	0	0	1,917	0.0087%	
WINTER PARK	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0.0000%	
TRANS-SERV	1,080,379	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	1,104,929	0	0	1,104,929	4.9947%	
TOTAL WHOLESALE	2,176,318							2,225,771	0	0	2,225,771	10.0613%	
TOTAL FPL	20,967,081							2,449,947	370,113	19,302,030	22,122,089	100.0000%	
JURIS SEPARATION FACTOR												0.899387	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
FPL101 - TRANSMISSION: 12CP Demand
December 2020 - PROJECTED

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	338,117	0	338,117	0.0000	0.4124	0.5876	1.0227	1.0378	1.0597	0	144,722	210,518	355,240	1.7103%	1.7855%
CILC-1G	13,812	0	13,812	0.0000	0.0216	0.9784	1.0227	1.0378	1.0597	0	310	14,320	14,630	0.0704%	0.0735%
CILC-1T	166,852	0	166,852	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	170,644	0	0	170,644	0.8216%	0.8577%
GS(T)-1	1,128,210	0	1,128,210	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	1,195,544	1,195,544	5.7560%	6.0089%
GSCU-1	11,416	0	11,416	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	12,097	12,097	0.0582%	0.0608%
GSD(T)-1	4,306,235	0	4,306,235	0.0000	0.0029	0.9971	1.0227	1.0378	1.0597	0	13,125	4,549,837	4,562,963	21.9687%	22.9337%
GSLD(T)-1	1,574,402	0	1,574,402	0.0000	0.0369	0.9631	1.0227	1.0378	1.0597	0	60,270	1,606,823	1,667,093	8.0263%	8.3789%
GSLD(T)-2	337,333	0	337,333	0.0000	0.3951	0.6049	1.0227	1.0378	1.0597	0	138,323	216,221	354,544	1.7070%	1.7820%
GSLD(T)-3	43,007	0	43,007	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	43,984	0	0	43,984	0.2118%	0.2211%
MET	11,756	0	11,756	0.0000	1.0000	0.0000	1.0227	1.0378	1.0597	0	12,200	0	12,200	0.0587%	0.0613%
OL-1	79	0	79	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	84	84	0.0004%	0.0004%
OS-2	782	0	782	0.0000	1.0000	0.0000	1.0227	1.0378	1.0597	0	812	0	812	0.0039%	0.0041%
RS(T)-1	10,844,890	0	10,844,890	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	11,492,136	11,492,136	55.3297%	57.7601%
SL-1	446	0	446	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	473	473	0.0023%	0.0024%
SL-1M	67	0	67	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	70	70	0.0003%	0.0004%
SL-2	3,546	0	3,546	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	3,758	3,758	0.0181%	0.0189%
SL-2M	87	0	87	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	92	92	0.0004%	0.0005%
SST-DST	391	0	391	0.0000	0.8637	0.1363	1.0227	1.0378	1.0597	0	350	56	407	0.0020%	0.0020%
SST-TST	9,335	0	9,335	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	9,547	0	0	9,547	0.0460%	0.0480%
TOTAL RETAIL	18,790,763	0	18,790,763							224,175	370,113	19,302,030	19,896,318	95.7922%	100.0000%
FKEC	124,145	0	124,145	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	126,966	0	0	126,966	0.6113%	
FPUC (INT)	13,177	(13,177)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0.0000%	
FPUC (PEAK)	14,405	(14,405)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0.0000%	
HOMESTEAD (INT)	4,400	(4,400)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0.0000%	
LCEC	717,529	0	717,529	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	733,834	0	0	733,834	3.5331%	
MOORE HAVEN	570	0	570	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	583	0	0	583	0.0028%	
NEW SMRYNA BCH	7,333	0	7,333	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	7,500	0	0	7,500	0.0361%	
NEW SMRYNA BCH (PEAK)	8,963	(8,963)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	4,889	(4,889)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0.0000%	
QUINCY	3,096	0	3,096	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	3,167	0	0	3,167	0.0152%	
SEMINOLE (INT)	195,556	(195,556)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0.0000%	
WAUCHULA	1,874	0	1,874	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	1,917	0	0	1,917	0.0092%	
WINTER PARK	0	0	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0.0000%	
TOTAL WHOLESALE	1,095,939	(241,390)	854,548							873,966	0	0	873,966	4.2078%	
TOTAL FPL	19,886,702	(241,390)	19,645,311							1,098,142	370,113	19,302,030	20,770,284	100.0000%	
JURIS SEPARATION FACTOR														0.957922	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
FPL101 - TRANSMISSION: 12CP Demand
December 2020 - PROJECTED

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	338,117	0	338,117	0.0000	0.4124	0.5876	1.0227	1.0378	1.0597	0	144,722	210,518	355,240	355,240	1.6811%	1.7855%
CILC-1G	13,812	0	13,812	0.0000	0.0216	0.9784	1.0227	1.0378	1.0597	0	310	14,320	14,630	14,630	0.0692%	0.0735%
CILC-1T	166,852	0	166,852	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	170,644	0	0	170,644	170,644	0.8076%	0.8577%
GS(T)-1	1,128,210	0	1,128,210	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	1,195,544	1,195,544	1,195,544	5.6578%	6.0089%
GSCU-1	11,416	0	11,416	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	12,097	12,097	12,097	0.0572%	0.0608%
GSD(T)-1	4,306,235	0	4,306,235	0.0000	0.0029	0.9971	1.0227	1.0378	1.0597	0	13,125	4,549,837	4,562,963	4,562,963	21.5937%	22.9337%
GSLD(T)-1	1,574,402	0	1,574,402	0.0000	0.0369	0.9631	1.0227	1.0378	1.0597	0	60,270	1,606,823	1,667,093	1,667,093	7.8893%	8.3789%
GSLD(T)-2	337,333	0	337,333	0.0000	0.3951	0.6049	1.0227	1.0378	1.0597	0	138,323	216,221	354,544	354,544	1.6778%	1.7820%
GSLD(T)-3	43,007	0	43,007	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	43,984	0	0	43,984	43,984	0.2081%	0.2211%
MET	11,756	0	11,756	0.0000	1.0000	0.0000	1.0227	1.0378	1.0597	0	12,200	0	12,200	12,200	0.0577%	0.0613%
OL-1	79	0	79	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	84	84	84	0.0004%	0.0004%
OS-2	782	0	782	0.0000	1.0000	0.0000	1.0227	1.0378	1.0597	0	812	0	812	812	0.0038%	0.0041%
RS(T)-1	10,844,890	0	10,844,890	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	11,492,136	11,492,136	11,492,136	54.3851%	57.7601%
SL-1	446	0	446	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	473	473	473	0.0022%	0.0024%
SL-1M	67	0	67	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	70	70	70	0.0003%	0.0004%
SL-2	3,546	0	3,546	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	3,758	3,758	3,758	0.0178%	0.0189%
SL-2M	87	0	87	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	92	92	92	0.0004%	0.0005%
SST-DST	391	0	391	0.0000	0.8637	0.1363	1.0227	1.0378	1.0597	0	350	56	407	407	0.0019%	0.0020%
SST-TST	9,335	0	9,335	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	9,547	0	0	9,547	9,547	0.0452%	0.0480%
TOTAL RETAIL	18,790,763	0	18,790,763							224,175	370,113	19,302,030	19,896,318	19,896,318	94.1569%	100.0000%
FKEC	124,145	0	124,145	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	126,966	0	0	126,966	126,966	0.6009%	
FPUC (INT)	13,177	0	13,177	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	13,476	0	0	13,476	21,803	0.1032%	
FPUC (PEAK)	14,405	(14,405)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0	0.0000%	
HOMESTEAD (INT)	4,400	0	4,400	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	4,500	0	0	4,500	7,281	0.0345%	
LCEC	717,529	0	717,529	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	733,834	0	0	733,834	733,834	3.4728%	
MOORE HAVEN	570	0	570	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	583	0	0	583	583	0.0028%	
NEW SMRYNA BCH	7,333	0	7,333	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	7,500	0	0	7,500	7,500	0.0355%	
NEW SMRYNA BCH (PEAK)	8,963	(8,963)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	4,889	0	4,889	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	5,000	0	0	5,000	8,089	0.0383%	
QUINCY	3,096	0	3,096	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	3,167	0	0	3,167	3,167	0.0150%	
SEMINOLE (INT)	195,556	0	195,556	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	200,000	0	0	200,000	323,579	1.5313%	
WAUCHULA	1,874	0	1,874	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	1,917	0	0	1,917	1,917	0.0091%	
WINTER PARK	0	0	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0	0.0000%	
TOTAL WHOLESALE	1,095,939	(23,368)	1,072,570							1,096,943	0	0	1,096,943	1,234,718	5.8431%	
TOTAL FPL	19,886,702	(23,368)	19,863,333							1,321,118	370,113	19,302,030	20,993,261	21,131,036	100.0000%	

JURIS SEPARATION FACTOR **0.941569**

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (INT) Amount	HOMESTEAD (INT) Amount	NS BEACH (INT) Amount	SEMINOLE (INT) Amount
1) Contract Wholesale Customer 12 CP	1	Contracted Demand	13,476	4,500	5,000	200,000
2) Intermediate System Capacity Net of Reserve Margin	2					
Intermediate Summer Capacity	3	2019-2028 TYSP	15,673,000	15,673,000	15,673,000	15,673,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%	120.0%	120.0%
Intermediate System Capacity Net of Reserve Margin	5	L3 / L4	13,060,833	13,060,833	13,060,833	13,060,833
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.001032	0.000345	0.000383	0.015313
3) Contract Adjusted 12CP @ Generation	7					
Total System 12CP Excluding All Stratified Contracts	8		20,770,284	20,770,284	20,770,284	20,770,284
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.98293	0.98293	0.98293	0.98293
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	21,131,036	21,131,036	21,131,036	21,131,036
Contract Adjusted 12CP @ Generation	11	L6 * L11	21,803	7,281	8,089	323,579

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
FPL101 - TRANSMISSION: 12CP Demand
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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	338,117	0	338,117	0.0000	0.4124	0.5876	1.0227	1.0378	1.0597	0	144,722	210,518	355,240	355,240	1.6970%	1.7855%
CILC-1G	13,812	0	13,812	0.0000	0.0216	0.9784	1.0227	1.0378	1.0597	0	310	14,320	14,630	14,630	0.0699%	0.0735%
CILC-1T	166,852	0	166,852	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	170,644	0	0	170,644	170,644	0.8152%	0.8577%
GS(T)-1	1,128,210	0	1,128,210	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	1,195,544	1,195,544	1,195,544	5.7112%	6.0089%
GSCU-1	11,416	0	11,416	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	12,097	12,097	12,097	0.0578%	0.0608%
GSD(T)-1	4,306,235	0	4,306,235	0.0000	0.0029	0.9971	1.0227	1.0378	1.0597	0	13,125	4,549,837	4,562,963	4,562,963	21.7975%	22.9337%
GSLD(T)-1	1,574,402	0	1,574,402	0.0000	0.0369	0.9631	1.0227	1.0378	1.0597	0	60,270	1,606,823	1,667,093	1,667,093	7.9638%	8.3789%
GSLD(T)-2	337,333	0	337,333	0.0000	0.3951	0.6049	1.0227	1.0378	1.0597	0	138,323	216,221	354,544	354,544	1.6937%	1.7820%
GSLD(T)-3	43,007	0	43,007	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	43,984	0	0	43,984	43,984	0.2101%	0.2211%
MET	11,756	0	11,756	0.0000	1.0000	0.0000	1.0227	1.0378	1.0597	0	12,200	0	12,200	12,200	0.0583%	0.0613%
OL-1	79	0	79	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	84	84	84	0.0004%	0.0004%
OS-2	782	0	782	0.0000	1.0000	0.0000	1.0227	1.0378	1.0597	0	812	0	812	812	0.0039%	0.0041%
RS(T)-1	10,844,890	0	10,844,890	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	11,492,136	11,492,136	11,492,136	54.8984%	57.7601%
SL-1	446	0	446	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	473	473	473	0.0023%	0.0024%
SL-1M	67	0	67	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	70	70	70	0.0003%	0.0004%
SL-2	3,546	0	3,546	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	3,758	3,758	3,758	0.0179%	0.0189%
SL-2M	87	0	87	0.0000	0.0000	1.0000	1.0227	1.0378	1.0597	0	0	92	92	92	0.0004%	0.0005%
SST-DST	391	0	391	0.0000	0.8637	0.1363	1.0227	1.0378	1.0597	0	350	56	407	407	0.0019%	0.0020%
SST-TST	9,335	0	9,335	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	9,547	0	0	9,547	9,547	0.0456%	0.0480%
TOTAL RETAIL	18,790,763	0	18,790,763							224,175	370,113	19,302,030	19,896,318	19,896,318	95.0455%	100.0000%
FKEC	124,145	0	124,145	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	126,966	0	0	126,966	126,966	0.6065%	
FPUC (INT)	13,177	(13,177)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0	0.0000%	
FPUC (PEAK)	14,405	0	14,405	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	14,733	0	0	14,733	100,595	0.4805%	
HOMESTEAD (INT)	4,400	(4,400)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0	0.0000%	
LCEC	717,529	0	717,529	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	733,834	0	0	733,834	733,834	3.5056%	
MOORE HAVEN	570	0	570	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	583	0	0	583	583	0.0028%	
NEW SMRYNA BCH	7,333	0	7,333	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	7,500	0	0	7,500	7,500	0.0358%	
NEW SMRYNA BCH (PEAK)	8,963	0	8,963	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	9,167	0	0	9,167	62,590	0.2990%	
NEW SMYRNA BCH (INT)	4,889	(4,889)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0	0.0000%	
QUINCY	3,096	0	3,096	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	3,167	0	0	3,167	3,167	0.0151%	
SEMINOLE (INT)	195,556	(195,556)	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0	0.0000%	
WAUCHULA	1,874	0	1,874	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	1,917	0	0	1,917	1,917	0.0092%	
WINTER PARK	0	0	0	1.0000	0.0000	0.0000	1.0227	1.0378	1.0597	0	0	0	0	0	0.0000%	
TOTAL WHOLESALE	1,095,939	(218,022)	877,917							897,866	0	0	897,866	1,037,151	4.9545%	
TOTAL FPL	19,886,702	(218,022)	19,668,680							1,122,041	370,113	19,302,030	20,794,184	20,933,469	100.0000%	

JURIS SEPARATION FACTOR **0.950455**

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (PEAK) Amount	NS BEACH (PEAK) Amount
1) Contract Wholesale Customer 12 CP	1	Contracted Demand	14,733	9,167
2) Peaking System Capacity Net of Reserve Margin	2			
Peaking Summer Capacity	3	2019-2027 TYS8	3,679,000	3,679,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%
Peaking System Capacity Net of Reserve Margin	5	L3 / L4	3,065,833	3,065,833
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.00481	0.00299
3) Contract Adjusted 12CP @ Generation	7			
Total System 12CP Excluding All Stratified Contracts	8		20,770,284	20,770,284
Contribution (Excluding Peaking Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99220	0.99220
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	20,933,469	20,933,469
Contract Adjusted 12CP @ Generation	11	L6 * L11	100,595	62,590

FLORIDA POWER & LIGHT
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FPL101 - TRANSMISSION: 12CP Demand
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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	2,581,432	0.0000	0.4066	0.5934	1.0174	1.0288	1.0454	0	1,079,747	1,601,418	2,681,165	2.2022%	2.3166%
CILC-1G	103,561	0.0000	0.0204	0.9796	1.0174	1.0288	1.0454	0	2,175	106,049	108,224	0.0889%	0.0935%
CILC-1T	1,372,502	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	1,396,358	0	0	1,396,358	1.1469%	1.2065%
GS(T)-1	6,318,956	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	6,605,637	6,605,637	5.4257%	5.7074%
GSCU-1	96,877	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	101,272	101,272	0.0832%	0.0875%
GSD(T)-1	27,177,649	0.0000	0.0030	0.9970	1.0174	1.0288	1.0454	0	83,046	28,326,271	28,409,317	23.3346%	24.5462%
GSLD(T)-1	9,978,344	0.0000	0.0344	0.9656	1.0174	1.0288	1.0454	0	353,347	10,072,010	10,425,357	8.5631%	9.0077%
GSLD(T)-2	2,567,503	0.0000	0.3927	0.6073	1.0174	1.0288	1.0454	0	1,037,373	1,629,914	2,667,287	2.1908%	2.3046%
GSLD(T)-3	312,336	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	317,765	0	0	317,765	0.2610%	0.2746%
MET	80,453	0.0000	1.0000	0.0000	1.0174	1.0288	1.0454	0	82,771	0	82,771	0.0680%	0.0715%
OL-1	95,120	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	99,436	99,436	0.0817%	0.0859%
OS-2	11,404	0.0000	1.0000	0.0000	1.0174	1.0288	1.0454	0	11,733	0	11,733	0.0096%	0.0101%
RS(T)-1	59,460,277	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	62,157,892	62,157,892	51.0547%	53.7056%
SL-1	524,215	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	547,998	547,998	0.4501%	0.4735%
SL-1M	5,936	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	6,205	6,205	0.0051%	0.0054%
SL-2	30,285	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	31,659	31,659	0.0260%	0.0274%
SL-2M	993	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	1,038	1,038	0.0009%	0.0009%
SST-DST	2,045	0.0000	0.9248	0.0752	1.0174	1.0288	1.0454	0	1,945	161	2,106	0.0017%	0.0018%
SST-TST	83,436	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	84,886	0	0	84,886	0.0697%	0.0733%
TOTAL RETAIL	110,803,324							1,799,010	2,652,137	111,286,960	115,738,107	95.0640%	100.0000%
FKEC	719,692	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	732,201	0	0	732,201	0.6014%	
FPUC (INT)	79,797	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	81,184	0	0	81,184	0.0667%	
FPUC (PEAK)	75,696	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	77,012	0	0	77,012	0.0633%	
HOMESTEAD (INT)	216	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	220	0	0	220	0.0002%	
LCEC	4,168,148	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	4,240,599	0	0	4,240,599	3.4831%	
MOORE HAVEN	28	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	28	0	0	28	0.0000%	
NEW SMRYNA BCH	360	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	366	0	0	366	0.0003%	
NEW SMYRNA BCH (INT)	240	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	244	0	0	244	0.0002%	
NEW SMRYNA BCH (PEAK)	12,120	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	12,331	0	0	12,331	0.0101%	
QUINCY	152	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	155	0	0	155	0.0001%	
SEMINOLE (INT)	850,206	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	864,984	0	0	864,984	0.7105%	
WAUCHULA	92	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	94	0	0	94	0.0001%	
WINTER PARK	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0.0000%	
TOTAL WHOLESALE	5,906,747							6,009,419	0	0	6,009,419	4.9360%	
TOTAL FPL	116,710,072							7,808,429	2,652,137	111,286,960	121,747,526	100.0000%	
JURIS SEPARATION FACTOR												0.950640	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
FPL101 - TRANSMISSION: 12CP Demand
December 2020 - PROJECTED

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	2,581,432	0	2,581,432	0.0000	0.4066	0.5934	1.0174	1.0288	1.0454	0	1,079,747	1,601,418	2,681,165	2.2211%	2.3166%
CILC-1G	103,561	0	103,561	0.0000	0.0204	0.9796	1.0174	1.0288	1.0454	0	2,175	106,049	108,224	0.0897%	0.0935%
CILC-1T	1,372,502	0	1,372,502	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	1,396,358	0	0	1,396,358	1.1568%	1.2065%
GS(T)-1	6,318,956	0	6,318,956	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	6,605,637	6,605,637	5.4722%	5.7074%
GSCU-1	96,877	0	96,877	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	101,272	101,272	0.0839%	0.0875%
GSD(T)-1	27,177,649	0	27,177,649	0.0000	0.0030	0.9970	1.0174	1.0288	1.0454	0	83,046	28,326,271	28,409,317	23.5349%	24.5462%
GSLD(T)-1	9,978,344	0	9,978,344	0.0000	0.0344	0.9656	1.0174	1.0288	1.0454	0	353,347	10,072,010	10,425,357	8.6366%	9.0077%
GSLD(T)-2	2,567,503	0	2,567,503	0.0000	0.3927	0.6073	1.0174	1.0288	1.0454	0	1,037,373	1,629,914	2,667,287	2.2096%	2.3046%
GSLD(T)-3	312,336	0	312,336	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	317,765	0	0	317,765	0.2632%	0.2746%
MET	80,453	0	80,453	0.0000	1.0000	0.0000	1.0174	1.0288	1.0454	0	82,771	0	82,771	0.0686%	0.0715%
OL-1	95,120	0	95,120	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	99,436	99,436	0.0824%	0.0859%
OS-2	11,404	0	11,404	0.0000	1.0000	0.0000	1.0174	1.0288	1.0454	0	11,733	0	11,733	0.0097%	0.0101%
RS(T)-1	59,460,277	0	59,460,277	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	62,157,892	62,157,892	51.4929%	53.7056%
SL-1	524,215	0	524,215	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	547,998	547,998	0.4540%	0.4735%
SL-1M	5,936	0	5,936	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	6,205	6,205	0.0051%	0.0054%
SL-2	30,285	0	30,285	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	31,659	31,659	0.0262%	0.0274%
SL-2M	993	0	993	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	1,038	1,038	0.0009%	0.0009%
SST-DST	2,045	0	2,045	0.0000	0.9248	0.0752	1.0174	1.0288	1.0454	0	1,945	161	2,106	0.0017%	0.0018%
SST-TST	83,436	0	83,436	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	84,886	0	0	84,886	0.0703%	0.0733%
TOTAL RETAIL	110,803,324	0	110,803,324							1,799,010	2,652,137	111,286,960	115,738,107	95.8799%	100.0000%
FKEC	719,692	0	719,692	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	732,201	0	0	732,201	0.6066%	
FPUC (INT)	79,797	(79,797)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0.0000%	
FPUC (PEAK)	75,696	(75,696)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0.0000%	
HOMESTEAD (INT)	216	(216)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0.0000%	
LCEC	4,168,148	0	4,168,148	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	4,240,599	0	0	4,240,599	3.5130%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	28	0	0	28	0.0000%	
NEW SMRYNA BCH	360	0	360	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	366	0	0	366	0.0003%	
NEW SMRYNA BCH (PEAK)	12,120	(12,120)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	240	(240)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0.0000%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	155	0	0	155	0.0001%	
SEMINOLE (INT)	850,206	(850,206)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0.0000%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	94	0	0	94	0.0001%	
WINTER PARK	0	0	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0.0000%	
TOTAL WHOLESALE	5,906,747	(1,018,276)	4,888,472							4,973,443	0	0	4,973,443	4.1201%	
TOTAL FPL	116,710,072	(1,018,276)	115,691,796							6,772,453	2,652,137	111,286,960	120,711,550	100.0000%	
JURIS SEPARATION FACTOR														0.958799	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
FPL101 - TRANSMISSION: 12CP Demand
December 2020 - PROJECTED

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	ADJUSTED	SYSTEM	RETAIL
CILC-1D	2,581,432	0	2,581,432	0.0000	0.4066	0.5934	1.0174	1.0288	1.0454	0	1,079,747	1,601,418	2,681,165	2,681,165	2.1832%	2.3166%
CILC-1G	103,561	0	103,561	0.0000	0.0204	0.9796	1.0174	1.0288	1.0454	0	2,175	106,049	108,224	108,224	0.0881%	0.0935%
CILC-1T	1,372,502	0	1,372,502	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	1,396,358	0	0	1,396,358	1,396,358	1.1370%	1.2065%
GS(T)-1	6,318,956	0	6,318,956	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	6,605,637	6,605,637	6,605,637	5.3788%	5.7074%
GSCU-1	96,877	0	96,877	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	101,272	101,272	101,272	0.0825%	0.0875%
GSD(T)-1	27,177,649	0	27,177,649	0.0000	0.0030	0.9970	1.0174	1.0288	1.0454	0	83,046	28,326,271	28,409,317	28,409,317	23.1331%	24.5462%
GSLD(T)-1	9,978,344	0	9,978,344	0.0000	0.0344	0.9656	1.0174	1.0288	1.0454	0	353,347	10,072,010	10,425,357	10,425,357	8.4891%	9.0077%
GSLD(T)-2	2,567,503	0	2,567,503	0.0000	0.3927	0.6073	1.0174	1.0288	1.0454	0	1,037,373	1,629,914	2,667,287	2,667,287	2.1719%	2.3046%
GSLD(T)-3	312,336	0	312,336	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	317,765	0	0	317,765	317,765	0.2587%	0.2746%
MET	80,453	0	80,453	0.0000	1.0000	0.0000	1.0174	1.0288	1.0454	0	82,771	0	82,771	82,771	0.0674%	0.0715%
OL-1	95,120	0	95,120	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	99,436	99,436	99,436	0.0810%	0.0859%
OS-2	11,404	0	11,404	0.0000	1.0000	0.0000	1.0174	1.0288	1.0454	0	11,733	0	11,733	11,733	0.0096%	0.0101%
RS(T)-1	59,460,277	0	59,460,277	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	62,157,892	62,157,892	62,157,892	50.6138%	53.7056%
SL-1	524,215	0	524,215	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	547,998	547,998	547,998	0.4462%	0.4735%
SL-1M	5,936	0	5,936	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	6,205	6,205	6,205	0.0051%	0.0054%
SL-2	30,285	0	30,285	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	31,659	31,659	31,659	0.0258%	0.0274%
SL-2M	993	0	993	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	1,038	1,038	1,038	0.0008%	0.0009%
SST-DST	2,045	0	2,045	0.0000	0.9248	0.0752	1.0174	1.0288	1.0454	0	1,945	161	2,106	2,106	0.0017%	0.0018%
SST-TST	83,436	0	83,436	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	84,886	0	0	84,886	84,886	0.0691%	0.0733%
TOTAL RETAIL	110,803,324	0	110,803,324							1,799,010	2,652,137	111,286,960	115,738,107	115,738,107	94.2430%	100.0000%
FKEC	719,692	0	719,692	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	732,201	0	0	732,201	732,201	0.5962%	
FPUC (INT)	79,797	0	79,797	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	81,184	0	0	81,184	126,713	0.1032%	
FPUC (PEAK)	75,696	(75,696)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0	0.0000%	
HOMESTEAD (INT)	216	0	216	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	220	0	0	220	42,313	0.0345%	
LCEC	4,168,148	0	4,168,148	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	4,240,599	0	0	4,240,599	4,240,599	3.4530%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	28	0	0	28	28	0.0000%	
NEW SMRYNA BCH	360	0	360	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	366	0	0	366	366	0.0003%	
NEW SMRYNA BCH (PEAK)	12,120	(12,120)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	240	0	240	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	244	0	0	244	47,014	0.0383%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	155	0	0	155	155	0.0001%	
SEMINOLE (INT)	850,206	0	850,206	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	864,984	0	0	864,984	1,880,556	1.5313%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	94	0	0	94	94	0.0001%	
WINTER PARK	0	0	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0	0.0000%	
TOTAL WHOLESALE	5,906,747	(87,816)	5,818,931							5,920,076	0	0	5,920,076	7,070,039	5.7570%	
TOTAL FPL	116,710,072	(87,816)	116,622,255							7,719,086	2,652,137	111,286,960	121,658,183	122,808,146	100.0000%	

JURIS SEPARATION FACTOR **0.942430**

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (INT) Amount	HOMESTEAD (INT) Amount	NS BEACH (INT) Amount	SEMINOLE (INT) Amount
1) Contract Wholesale Customer 12 CP	1	Load Research * Loss Factor	13,476	4,500	5,000	200,000
2) Intermediate System Capacity Net of Reserve Margin	2					
Intermediate Summer Capacity	3	2019-2028 TYSP	15,673,000	15,673,000	15,673,000	15,673,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%	120.0%	120.0%
Intermediate System Capacity Net of Reserve Margin	5	L3 / L4	13,060,833	13,060,833	13,060,833	13,060,833
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.001032	0.000345	0.000383	0.015313
3) Contract Adjusted 12CP @ Generation	7					
Total System 12CP Excluding All Stratified Contracts	8		120,711,550	120,711,550	120,711,550	120,711,550
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.98293	0.98293	0.98293	0.98293
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	122,808,146	122,808,146	122,808,146	122,808,146
Contract Adjusted 12CP @ Generation	11	L6 * L11	126,713	42,313	47,014	1,880,556

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
FPL101 - TRANSMISSION: 12CP Demand
December 2020 - PROJECTED

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	ADJUSTED	SYSTEM	RETAIL
CILC-1D	2,581,432	0	2,581,432	0.0000	0.4066	0.5934	1.0174	1.0288	1.0454	0	1,079,747	1,601,418	2,681,165	2,681,165	2.2038%	2.3166%
CILC-1G	103,561	0	103,561	0.0000	0.0204	0.9796	1.0174	1.0288	1.0454	0	2,175	106,049	108,224	108,224	0.0890%	0.0935%
CILC-1T	1,372,502	0	1,372,502	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	1,396,358	0	0	1,396,358	1,396,358	1.1478%	1.2065%
GS(T)-1	6,318,956	0	6,318,956	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	6,605,637	6,605,637	6,605,637	5.4296%	5.7074%
GSCU-1	96,877	0	96,877	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	101,272	101,272	101,272	0.0832%	0.0875%
GSD(T)-1	27,177,649	0	27,177,649	0.0000	0.0030	0.9970	1.0174	1.0288	1.0454	0	83,046	28,326,271	28,409,317	28,409,317	23.3514%	24.5462%
GSLD(T)-1	9,978,344	0	9,978,344	0.0000	0.0344	0.9656	1.0174	1.0288	1.0454	0	353,347	10,072,010	10,425,357	10,425,357	8.5693%	9.0077%
GSLD(T)-2	2,567,503	0	2,567,503	0.0000	0.3927	0.6073	1.0174	1.0288	1.0454	0	1,037,373	1,629,914	2,667,287	2,667,287	2.1924%	2.3046%
GSLD(T)-3	312,336	0	312,336	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	317,765	0	0	317,765	317,765	0.2612%	0.2746%
MET	80,453	0	80,453	0.0000	1.0000	0.0000	1.0174	1.0288	1.0454	0	82,771	0	82,771	82,771	0.0680%	0.0715%
OL-1	95,120	0	95,120	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	99,436	99,436	99,436	0.0817%	0.0859%
OS-2	11,404	0	11,404	0.0000	1.0000	0.0000	1.0174	1.0288	1.0454	0	11,733	0	11,733	11,733	0.0096%	0.0101%
RS(T)-1	59,460,277	0	59,460,277	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	62,157,892	62,157,892	62,157,892	51.0915%	53.7056%
SL-1	524,215	0	524,215	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	547,998	547,998	547,998	0.4504%	0.4735%
SL-1M	5,936	0	5,936	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	6,205	6,205	6,205	0.0051%	0.0054%
SL-2	30,285	0	30,285	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	31,659	31,659	31,659	0.0260%	0.0274%
SL-2M	993	0	993	0.0000	0.0000	1.0000	1.0174	1.0288	1.0454	0	0	1,038	1,038	1,038	0.0009%	0.0009%
SST-DST	2,045	0	2,045	0.0000	0.9248	0.0752	1.0174	1.0288	1.0454	0	1,945	161	2,106	2,106	0.0017%	0.0018%
SST-TST	83,436	0	83,436	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	84,886	0	0	84,886	84,886	0.0698%	0.0733%
TOTAL RETAIL	110,803,324	0	110,803,324							1,799,010	2,652,137	111,286,960	115,738,107	115,738,107	95.1325%	100.0000%
FKEC	719,692	0	719,692	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	732,201	0	0	732,201	732,201	0.6018%	
FPUC (INT)	79,797	(79,797)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0	0.0000%	
FPUC (PEAK)	75,696	0	75,696	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	77,012	0	0	77,012	584,633	0.4805%	
HOMESTEAD (INT)	216	(216)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0	0.0000%	
LCEC	4,168,148	0	4,168,148	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	4,240,599	0	0	4,240,599	4,240,599	3.4856%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	28	0	0	28	28	0.0000%	
NEW SMRYNA BCH	360	0	360	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	366	0	0	366	366	0.0003%	
NEW SMRYNA BCH (PEAK)	12,120	0	12,120	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	12,331	0	0	12,331	363,756	0.2990%	
NEW SMYRNA BCH (INT)	240	(240)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0	0.0000%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	155	0	0	155	155	0.0001%	
SEMINOLE (INT)	850,206	(850,206)	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0	0.0000%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	94	0	0	94	94	0.0001%	
WINTER PARK	0	0	0	1.0000	0.0000	0.0000	1.0174	1.0288	1.0454	0	0	0	0	0	0.0000%	
TOTAL WHOLESALE	5,906,747	(930,459)	4,976,288							5,062,786	0	0	5,062,786	5,921,833	4.8675%	
TOTAL FPL	116,710,072	(930,459)	115,779,612							6,861,796	2,652,137	111,286,960	120,800,893	121,659,940	100.0000%	

JURIS SEPARATION FACTOR **0.951325**

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (PEAK) Amount	NEW SMYRNA BEACH (PEAK) Amount
1) Contract Wholesale Customer 12 CP	1	Load Research * Loss Factor	14,733	9,167
2) Peaking System Capacity Net of Reserve Margin	2			
Peaking Summer Capacity	3	2019-2027 TYS8	3,679,000	3,679,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%
Peaking System Capacity Net of Reserve Margin	5	L3 / L4	3,065,833	3,065,833
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.00481	0.00299
3) Contract Adjusted 12CP @ Generation	7			
Total System 12CP Excluding All Stratified Contracts	8		120,711,550	120,711,550
Contribution (Excluding Peaking Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99220	0.99220
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	121,659,940	121,659,940
Contract Adjusted 12CP @ Generation	11	L6 * L11	584,633	363,756

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
SEP - Internals Based on Externals (B2S)
December 2020 - PROJECTED

SEP - INTERNAL FACTORS BASED ON EXTERNAL FACTORS	ALLOCATOR	COMPANY PER BOOKS	SEPARATION FACTOR	JURISDICTIONAL	INTERNAL SEPARATION FACTOR
I900-LABOR-EXC-A&G					
L_INC100000 - STEAM O&M PAY - OPERAT SUPERV & ENG		1,458,485.11	0.954562	1,392,214.89	
L_INC101210 - STEAM O&M PAY - FUEL - NON RECOVERABLE OIL		344,728.15	0.952960	328,512.20	
L_INC102000 - STEAM O&M PAY - STEAM EXPENSES		931,196.41	0.956985	891,141.19	
L_INC105000 - STEAM O&M PAY - ELECTRIC EXPENSES		540,673.25	0.953803	515,695.89	
L_INC106000 - STEAM O&M PAY - MISC STEAM POWER EXPENSES		7,365,494.72	0.951362	7,007,252.96	
L_INC110000 - STEAM O&M PAY - MAINT SUPERV & ENG		743,460.07	0.956691	711,261.85	
L_INC111000 - STEAM O&M PAY - MAINT OF STRUCTURES		1,621,816.59	0.951761	1,543,582.30	
L_INC112000 - STEAM O&M PAY - MAINT OF BOILER PLANT		2,852,726.87	0.955888	2,726,887.45	
L_INC113000 - STEAM O&M PAY - MAINT OF ELECTRIC PLANT		1,298,756.46	0.953753	1,238,692.79	
L_INC114000 - STEAM O&M PAY - MAINT OF MISC STEAM PLT		943,482.13	0.953514	899,623.48	
L_INC117000 - NUCLEAR O&M PAY - OPER SUPERV & ENG		42,457,007.49	0.957922	40,670,513.03	
L_INC119000 - NUCLEAR O&M PAY - COOLANTS AND WATER		6,876,967.57	0.957922	6,587,600.39	
L_INC120000 - NUCLEAR O&M PAY - STEAM EXPENSES		46,515,775.46	0.957922	44,558,497.27	
L_INC123000 - NUCLEAR O&M PAY - ELECTRIC EXP		21,836.20	0.957922	20,917.38	
L_INC124000 - NUCLEAR O&M PAY - MISC NUCLEAR POWER EXP		19,647,709.77	0.957922	18,820,978.76	
L_INC128000 - NUCLEAR O&M PAY - MAINT SUPERVISION & ENGINEERING		46,815,593.50	0.958799	44,886,741.56	
L_INC129000 - NUCLEAR O&M PAY - MAINT OF STRUCTURES		99,805.55	0.957922	95,605.96	
L_INC130000 - NUCLEAR O&M PAY - MAINT OF REACTOR PLANT		56,495.43	0.950640	53,706.83	
L_INC131000 - NUCLEAR O&M PAY - MAINT OF ELECTRIC PLANT		549,497.87	0.950640	522,374.83	
L_INC132000 - NUCLEAR O&M PAY - MAINT OF MISC NUCLEAR PLANT		6,162.61	0.950640	5,858.43	
L_INC146000 - OTH PWR O&M PAY - OPERAT SUPERV & ENG		9,925,210.41	0.945071	9,380,030.71	
L_INC147200 - OTH PWR O&M PAY - FUEL N- RECOV EMISSIONS FEE		3,000,366.27	0.942430	2,827,635.81	
L_INC148000 - OTH PWR O&M PAY- GENERATION EXPENSES		9,099,129.15	0.942311	8,574,213.76	
L_INC149000 - OTH PWR O&M PAY - MISC OTHER POWER GENERATION EXPE		17,728,556.10	0.943000	16,718,020.71	
L_INC151000 - OTH PWR O&M PAY - MAINT SUPERV & ENG		5,280,538.84	0.943471	4,982,033.41	
L_INC152000 - OTH PWR O&M PAY - MAINT OF STRUCTURES		4,420,827.76	0.942063	4,164,698.46	
L_INC153000 - OTH PWR O&M PAY - MAINT GENERATING & ELECTRIC PLANT		22,139,441.74	0.943360	20,885,453.02	
L_INC154000 - OTH PWR O&M PAY - MAINT MISC OTHER PWR GENERAT		3,713,703.71	0.942812	3,501,323.05	
L_INC156000 - OTH PWR O&M PAY - SYSTEM CONTROL & LOAD DISPATCH		716,148.84	0.941569	674,303.20	
L_INC157000 - OTH PWR O&M PAY - OTHER EXPENSES LOC 955		1,778,615.65	0.941569	1,674,688.47	
L_INC260010 - TRANS O&M PAY - OPERATION SUPERV & ENGINEERING		4,291,237.49	0.899387	3,859,482.96	
L_INC261000 - TRANS O&M PAY - LOAD DISPATCHING		2,626,048.95	0.899387	2,361,834.12	
L_INC262000 - TRANS O&M PAY - STATION EXPENSES		267,923.29	0.899387	240,966.71	
L_INC263000 - TRANS O&M PAY - OVERHEAD LINE EXPENSES		80,731.87	0.899387	72,609.19	
L_INC266000 - TRANS O&M PAY - MISC TRANSMISSION EXPENSES		3,531,239.58	0.899387	3,175,950.76	
L_INC267000 - TRANS O&M - RENTS					
L_INC268010 - TRANS O&M PAY - MAINT SUPERV & ENG		1,278,133.29	0.899387	1,149,536.39	
L_INC269000 - TRANS O&M PAY - MAINT OF STRUCTURES		2,459,633.36	0.899387	2,212,162.12	
L_INC270000 - TRANS O&M PAY - MAINT OF STATION EQ		1,812,986.06	0.899387	1,630,575.98	
L_INC271000 - TRANS O&M PAY - MAINT OF OVERHEAD LINES		1,968,736.85	0.899387	1,770,656.21	
L_INC272000 - TRANS O&M PAY - MAINT UNDERGROUND LINES		28,707.50	0.899387	25,819.15	
L_INC273000 - TRANS O&M PAY - MAINT OF MISC TRANS PLANT					
L_INC380000 - DIST O&M PAY - OPERATION SUPERVISION AND ENGINEERING		11,255,050.98	1.000000	11,255,050.98	
L_INC381000 - DIST O&M PAY - LOAD DISPATCHING					
L_INC382000 - DIST O&M PAY - SUBSTATION EXPENSES		762,778.60	1.000000	762,778.60	
L_INC383000 - DIST O&M PAY - OVERHEAD LINE EXPENSES		3,860,490.63	1.000000	3,860,490.63	
L_INC384000 - DIST O&M PAY - UNDERGROUND LINE EXP		1,281,168.82	1.000000	1,281,168.82	
L_INC385000 - DIST O&M PAY - STREET LIGHTING AND SIGNAL SYSTEM EXPEI		168,626.77	1.000000	168,626.77	
L_INC386000 - DIST O&M PAY - METER EXPENSES		8,572,209.94	0.996532	8,542,482.33	
L_INC387000 - DIST O&M PAY - CUSTOMER INSTALLATIONS EXP		970,652.69	1.000000	970,652.69	
L_INC388000 - DIST O&M PAY - MISC DISTRIBUTION EXPENSES		28,906,356.24	1.000000	28,906,356.24	
L_INC389000 - DIST O&M - RENTS					
L_INC390000 - DIST O&M PAY - MAINT SUPERV & ENG		17,164,338.31	1.000000	17,164,338.31	
L_INC391000 - DIST O&M PAY - MAINT OF STRUCTURES		43,981.25	1.000000	43,981.25	
L_INC392000 - DIST O&M PAY - MAINT OF STATION EQ		2,820,650.54	1.000000	2,820,650.54	
L_INC393000 - DIST O&M PAY - MAINT OF OVERHEAD LINES		26,862,279.55	1.000000	26,862,279.55	
L_INC394000 - DIST O&M PAY - MAINT UNDERGROUND LINES		11,445,954.26	1.000000	11,445,954.26	
L_INC395000 - DIST O&M PAY - MAINT OF LINE TRANSFORMERS		48,554.34	1.000000	48,554.34	
L_INC396000 - DIST O&M PAY - MAINT OF STREET LIGHTING & SIGNAL SYSTEI		4,103,494.18	1.000000	4,103,494.18	
L_INC397000 - DIST O&M PAY - MAINT OF METERS		2,314,255.86	0.996532	2,306,230.24	
L_INC398000 - DIST O&M PAY - MAINT OF MISC DISTRI PLT		2,223,462.75	1.000000	2,223,462.75	
L_INC401000 - CUST ACCT O&M PAY - SUPERVISION		4,620,679.97	1.000000	4,620,679.97	
L_INC402000 - CUST ACCT O&M PAY - METER READING EXP		3,819,296.78	1.000000	3,819,296.78	
L_INC403000 - CUST ACCT O&M PAY - CUST REC & COLLECT		35,434,085.70	1.000000	35,434,085.70	
L_INC404000 - CUST ACCT EXP - UNCOLLECTIBLE ACCOUNTS					
L_INC405000 - CUST ACCT O&M PAY - MISC CUSTOMER ACCOUNTS EXPENSE					
L_INC407000 - CUST SERV & INFO PAY - SUPERVISION		753,005.07	1.000000	753,005.07	
L_INC408000 - CUST SERV & INFO PAY - CUST ASSIST EXP		2,121,731.28	1.000000	2,121,731.28	
L_INC409000 - CUST SERV & INFO PAY - INFO & INST ADV - GENERAL					
L_INC410000 - CUST SERV & INFO PAY - MISC CUST SERV & INF		5,008,598.14	1.000000	5,008,598.14	
L_INC411000 - SUPERVISION-SALES EXPENSES					
L_INC516000 - MISC AND SELLING EXPENSES		710,045.79	1.000000	710,045.79	
Total I900-LABOR-EXC-A&G		452,567,336.37		438,593,648.85	**0.969124**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 24
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)

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

TABLE 1

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

TABLE 2

(1)	(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	19,552,597	0	0	0	0	0	19,552,597	0
February	4,292,999	0	0	0	0	0	4,292,999	0
March	4,374,374	0	0	0	0	0	4,374,374	0
April	1,780,031	671,019	0	0	0	0	2,451,050	0
May	0	4,176,387	0	0	0	0	4,176,387	0
June	0	3,932,365	0	0	0	0	3,932,365	0
July	0	1,220,230	766,205	1,149,308	0	0	1,986,435	1,149,308
August	0	0	1,185,973	1,778,959	0	0	1,185,973	1,778,959
September	0	0	2,016,757	3,025,135	0	0	2,016,757	3,025,135
October	0	0	2,262,116	3,393,174	0	0	2,262,116	3,393,174
November	0	0	1,281,073	1,921,609	0	0	1,281,073	1,921,609
December	0	0	1,449,610	2,174,415	0	0	1,449,610	2,174,415
Total	**30,000,000**	**10,000,000**	**8,961,733**	**13,442,599**	**0**	**0**	**48,961,733**	**13,442,599**

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

Wholesale Sales - Table 1

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

Wholesale Purchases - Table 2

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

ASSET OPTIMIZATION DETAIL

Actual for the Period of: January 2018 through December 2018

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

Docket No. 20190001-EI
Asset Optimization Detail
Exhibit GJY-1, Page 3 of 4

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

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

*Includes software and hardware expenses

APPENDIX I

FUEL COST RECOVERY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 25
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: G. J. Yupp GJY-2

EXHIBIT GJY-2

DOCKET NO. 20190001-EI

PAGES 1-4

SEPTEMBER 3, 2019

APPENDIX I

FUEL COST RECOVERY

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PAGE	DESCRIPTION	SPONSOR
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 2020 Through December 2020

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.7% Sulfur Grade ($/Bbl)	72.60	72.50	72.40	72.30	72.20	72.10	72.00	71.90	71.80	71.75	71.70	71.65
0.7% Sulfur Grade ($/MMBtu)	11.34	11.33	11.31	11.30	11.28	11.27	11.25	11.23	11.22	11.21	11.20	11.20
Light Oil	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Ultra-Low Sulfur Distillate ($/Bbl)	86.44	86.22	85.80	85.21	84.84	84.60	84.63	84.71	84.82	84.90	84.97	84.94
Ultra-Low Sulfur Distillate ($/MMBtu)	14.83	14.79	14.72	14.62	14.55	14.51	14.52	14.53	14.55	14.56	14.57	14.57
Natural Gas Transportation	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Firm FGT (MMBtu/Day)	1,150,000	1,150,000	1,150,000	1,239,000	1,274,000	1,274,000	1,274,000	1,274,000	1,274,000	1,239,000	1,150,000	1,150,000
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
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
Sabal Trail/FSC (MMBtu/Day)	400,000	400,000	400,000	400,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Total Projected Daily Availability (MMBtu/Day)	2,395,000	2,395,000	2,395,000	2,484,000	2,694,000	2,669,000	2,619,000	2,619,000	2,619,000	2,609,000	2,595,000	2,595,000
Southeast Supply Header (SESH)**	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000
Transcontinental Pipe Line (Transco)**	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500	121,500
Gulf South Pipeline Company (Gulf South)**	200,000	200,000	200,000	345,000	345,000	345,000	345,000	345,000	345,000	345,000	200,000	200,000
**Note: SESH,Transco and Gulf South firm transportation does not provide increased capacity to FPL's plants but does increase FPL's access to on-shore supply.												
Natural Gas Dispatch Price	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Firm FGT ($/MMBtu)	2.62	2.60	2.53	2.37	2.37	2.42	2.47	2.49	2.47	2.49	2.54	2.71
Firm Gulfstream ($/MMBtu)	2.58	2.56	2.48	2.28	2.28	2.33	2.38	2.40	2.38	2.40	2.49	2.66
Firm Sabal Trail/FSC ($/MMBtu)	2.63	2.62	2.51	2.35	2.35	2.40	2.45	2.47	2.45	2.47	2.54	2.71
Non-Firm FGT ($/MMBtu)	3.66	3.63	3.56	3.38	3.40	3.45	3.50	3.52	3.50	3.50	3.58	3.74
Non-Firm Gulfstream ($/MMBtu)	3.50	3.47	3.41	3.22	3.24	3.29	3.35	3.36	3.34	3.34	3.43	3.58
Coal	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Scherer ($/MMBtu)	2.56	2.55	2.54	2.53	2.52	2.54	2.57	2.58	2.58	2.58	2.59	2.59

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral 3	0.6	5.5	9.2	02/12/20 - 03/26/20	02/29/20 - 03/27/20			
Ft. Myers 2	0.5	5.5	4.5	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
Ft. Myers 3A	1.0	5.5	1.9	12/01/20 - 12/07/20				
Ft. Myers 3B	1.0	5.5	1.9	12/01/20 - 12/07/20				
Ft. Myers 3C	1.0	5.5	1.9	12/08/20 - 12/14/20				
Ft. Myers 3D	1.0	5.5	1.9	12/08/20 - 12/14/20				
Lauderdale 6A	0.5	5.5	1.9	01/16/20 - 01/22/20				
Lauderdale 6B	0.5	5.5	1.9	01/23/20 - 01/29/20				
Lauderdale 6C	0.5	5.5	1.9	01/23/20 - 01/29/20				
Lauderdale 6D	0.5	5.5	1.9	01/30/20 - 02/05/20				
Lauderdale 6E	0.5	5.5	1.9	01/30/20 - 02/05/20				
Manatee 1	0.3	3.5	6.6	01/11/20 - 01/24/20	04/30/20 - 05/09/20			
Manatee 2	0.3	3.5	3.8	03/28/20 - 04/10/20				
Manatee 3	0.4	5.5	2.9	11/12/20 - 11/18/20	11/19/20 - 11/25/20			
Martin 3	0.6	5.5	1.9	11/30/20 - 12/06/20				
Martin 4	0.5	5.0	14.8	10/01/20 - 11/23/20				
Martin 8	0.5	5.5	4.6	04/05/20 - 05/02/20	05/05/20 - 06/14/20	05/17/20 - 05/28/20		
Okeechobee 1	0.5	2.8	3.8	03/14/20 - 03/20/20	03/14/20 - 03/27/20			
Port Everglades 5	0.6	5.5	7.2	04/05/20 - 05/02/20	05/05/20 - 06/14/20	05/17/20 - 05/28/20		
Riviera 5	0.6	5.5	7.7	10/15/20 - 11/11/20				
Sanford 4	0.4	4.6	20.5	03/01/20 - 05/14/20				
Sanford 5	0.5	5.5	1.9	01/26/20 - 02/01/20				
Scherer 4	1.6	3.2	13.9	03/01/20 - 04/20/20				
St. Lucie 1	1.3	1.3	0.0	NONE				
St. Lucie 2	1.2	1.2	7.9	02/17/20 - 03/17/20				
Turkey Point 3	1.2	1.2	7.9	03/30/20 - 04/28/20				
Turkey Point 4	1.1	1.1	10.9	10/05/20 - 11/14/20				
Turkey Point 5	0.5	5.5	3.7	09/01/20 - 09/07/20	09/01/20 - 09/10/20	09/29/20 - 10/08/20		
West County 1	0.6	5.0	24.1	03/20/20 - 04/08/20	05/01/20 - 05/20/20	10/07/20 - 12/20/20		
West County 2	0.6	5.5	2.9	04/09/20 - 04/18/20	04/11/20 - 04/15/20	04/11/20 - 04/20/20	04/13/20 - 04/22/20	
West County 3	0.6	5.5	6.6	09/06/20 - 09/29/20	09/09/20 - 10/02/20	09/12/20 - 09/29/20	09/12/20 - 10/05/20	

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2018

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 26
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: C. R. Rote CRR-1

CRR-1
DOCKET NO. 20190001-EI
FPL Witness: Charles R. Rote
Exhibit No.: _____
Pages 1 - 20
March 15, 2019

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2018

INDEX OF MANUAL PAGES	TITLES
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, 2018

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)			GENERATING PERFORMANCE INCENTIVE FACTOR ($000)		
+ 10		45,647			22,824		
+ 9		41,082			20,541		
+ 8		36,518			18,259		
+ 7		31,953			15,976		
+ 6		27,388			13,694		
+ 5		22,824			11,412		
+ 4	<--------- 3.758	18,259	<---------	17,151.736	9,129	<--------	8,577.071
+ 3		13,694			6,847		
+ 2		9,129			4,565		
+ 1		4,565			2,282		
0		0			0		
- 1		(4,565)			(2,282)		
- 2		(9,129)			(4,565)		
- 3		(13,694)			(6,847)		
- 4		(18,259)			(9,129)		
- 5		(22,824)			(11,412)		
- 6		(27,388)			(13,694)		
- 7		(31,953)			(15,976)		
- 8		(36,518)			(18,259)		
- 9		(41,082)			(20,541)		
- 10		(45,647)			(22,824)		

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2018

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 17,039,980,508
LINE 2	MONTH OF January	2018	$ 17,231,915,335
LINE 3	MONTH OF February	2018	$ 17,367,636,164
LINE 4	MONTH OF March	2018	$ 18,374,364,290
LINE 5	MONTH OF April	2018	$ 18,555,312,395
LINE 6	MONTH OF May	2018	$ 18,758,413,965
LINE 7	MONTH OF June	2018	$ 19,000,176,165
LINE 8	MONTH OF July	2018	$ 19,253,374,129
LINE 9	MONTH OF August	2018	$ 20,375,380,592
LINE 10	MONTH OF September	2018	$ 20,526,422,175
LINE 11	MONTH OF October	2018	$ 20,692,337,885
LINE 12	MONTH OF November	2018	$ 20,863,944,805
LINE 13	MONTH OF December	2018	$ 20,429,221,803
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 19,112,960,016
LINE 15	25 BASIS POINTS		0.0025
LINE 16	REVENUE EXPANSION FACTOR		74.6012%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 64,050,403
LINE 18	JURISDICTIONAL SALES		110,053,140,000 KWH
LINE 19	TOTAL SALES		116,843,083,000 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		94.19%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 60,329,075
LINE 22	INCENTIVE CAP (50 PERCENT OF PROJECTED FUEL SAVINGS AT 10 GPIF·POINT LEVEL FROM SHEET NO. 3.515)		$ 22,823,500
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)		$ 22,823,500

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, 2018

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Cape Canaveral 3	EAF	3.01	10.00	.3010
Cape Canaveral 3	ANOHR	5.93	0.00	.0000
Manatee 3	EAF	1.13	-10.00	-.1130
Manatee 3	ANOHR	6.50	1.15	.0748
Ft. Myers 2	EAF	1.27	10.00	.1270
Ft. Myers 2	ANOHR	5.66	2.93	.1658
Martin 8	EAF	1.44	10.00	.1440
Martin 8	ANOHR	6.01	0.00	.0000
Riviera 5	EAF	2.96	-2.00	-.0592
Riviera 5	ANOHR	4.54	10.00	.4540
St. Lucie 1	EAF	8.58	10.00	.8580
St. Lucie 1	ANOHR	1.06	0.00	.0000
St. Lucie 2	EAF	7.10	10.00	.7100
St. Lucie 2	ANOHR	0.78	0.00	.0000
Turkey Point 3	EAF	6.83	10.00	.6830
Turkey Point 3	ANOHR	1.57	2.84	.0446
Turkey Point 4	EAF	7.88	10.00	.7880
Turkey Point 4	ANOHR	1.89	0.00	.0000
West County 1	EAF	2.84	10.00	.2840
West County 1	ANOHR	6.66	-10.00	-.6660
West County 2	EAF	2.74	-10.00	-.2740
West County 2	ANOHR	6.01	0.00	.0000
West County 3	EAF	2.36	10.00	.2360
West County 3	ANOHR	5.25	0.00	.0000
		---		---
GPIF System Total:		100		3.7580

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2018

1	2	3	4	5	6	7	8	9			
	ACTUAL				PLANNED OUTAGE ADJ TO EAF [1]	ADJUSTED ACTUAL EAF	TARGET EAF	POINTS FROM TABLES	ORIGINAL PLANNED OUTAGE DATES	ACTUAL OUTAGE DATES	ACTUAL FUEL SAVINGS/ (LOSS) ($000)
UNIT	FOF	MOF	POF	EAF							
Cape Canaveral 3	0.6	5.9	2.1	91.4	-0.6	90.8	86.4	10.00	05/30/18 - 06/08/18; 06/09/18 - 06/18/18 06/19/18 - 06/28/18	5/15/18-6/7/18	1,373.0
Manatee 3	0.1	7.2	0.0	92.6	-2.7	89.9	92.9	-10.00	03/03/18 - 03/09/18; 03/10/18 - 03/16/18 03/17/18 - 03/23/18	NONE	(517.0)
Ft. Myers 2	0.3	2.1	8.9	88.7	0.0	88.7	85.9	10.00	02/15/18 - 02/28/18; 02/15/18 - 02/21/18 02/22/18 - 02/28/18; 10/31/18 - 12/24/18 11/07/18 - 12/31/18	11/13/18-12/15/18; 2/22/18-4/12/18 2/14/18-4/7/18; 11/18/18-12/31/18 3/4/18-3/18/18; 3/5/18-3/19/18	578.0
Martin 8	0.1	3.7	11.6	84.7	-1.5	83.2	80.5	10.00	01/30/18 - 02/15/18; 02/16/18 - 03/01/18 10/13/18 - 12/10/18; 10/20/18 - 12/17/18 11/15/18 - 12/05/18	11/17/18-12/11/18; 10/12/18-12/12/18 10/20/18-12/16/18 & 12/18-19/18 11/17/18-12/11/18	657.0
Riviera 5	1.2	5.3	8.3	85.2	-0.3	84.9	85.4	-2.00	09/15/18 - 10/29/18; 11/01/18 - 12/19/18	11/2/18-12/16/18; 9/14/18-11/2/18	(270.2)
St. Lucie 1	0.5	0.0	8.7	90.8	0.5	91.3	85.0	10.00	03/12/18 - 04/11/18	3/10/18-4/13/18	3,916.0
St. Lucie 2	2.6	0.0	9.6	87.8	1.1	88.9	85.1	10.00	08/27/18 - 09/27/18	5/3/18-5/3/18; 8/26/18-10/5/18	3,241.0
Turkey Point 3	0.0	0.0	11.4	88.6	-0.1	88.5	82.1	10.00	10/01/18 - 11/12/18	9/29/18-11/12/18	3,119.0
Turkey Point 4	0.0	0.0	0.3	99.6	0.4	100.0	93.6	10.00	NONE	8/13/18-8/15/18	3,597.0
West County 1	0.1	3.7	13.4	82.8	0.9	83.7	79.1	10.00	05/09/18 - 06/03/18; 05/19/18 - 05/28/18 11/15/18 - 12/14/18	11/9/18-12/20/18; 10/30/18-12/11/18 4/10/18-5/20/18; 11/14/18-12/9/18	1,297.0
West County 2	0.3	12.2	0.0	87.4	-4.7	82.7	89.3	-10.00	02/16/18 - 03/05/18; 02/19/18 - 03/08/18 02/21/18 - 03/10/18; 02/21/18 - 03/05/18	NONE	(1,252.0)
West County 3	0.3	6.9	10.0	82.8	-2.2	80.6	80.4	10.00	03/17/18 - 05/08/18; 06/04/18 - 07/26/18 12/01/18 - 12/10/18	4/29/18-6/18/18; 6/18-20/18 & 6/22/18 2/19/18-4/18/18	1,075.0
											16,813.800

(1) EQUIVALENT AVAILABILITY ADJUSTMENT DUE TO PLANNED OUTAGE ACTUAL DURATION VERSUS TARGET DURATION
SEE 6.203.006 FOR FORMULAS AND CALCULATION DATA

EQUIVALENT AVAILABILITY ADJUSTMENTS
JANUARY THROUGH DECEMBER, 2018

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	EPOH	EAF%
Cape Canaveral 3	8760	50.5	520.9	181.8	2.7	240.0	90.8
Manatee 3	8760	12.6	635.0	0.0	2.9	252.0	89.9
Ft. Myers 2	8760	27.4	182.6	776.6	8.9	776.0	88.7
Martin 8	8760	10.0	321.5	1012.6	13.1	1146.0	83.2
Riviera 5	8760	103.1	467.0	728.1	8.6	752.0	84.9
St. Lucie 1	8760	41.9	0.0	766.1	8.2	720.0	91.3
St. Lucie 2	8760	228.4	0.0	836.7	8.5	744.0	88.9
Turkey Point 3	8760	1.6	0.0	1000.8	11.5	1008.0	88.5
Turkey Point 4	8760	3.1	0.0	28.1	0.0	0.0	100.0
West County 1	8760	12.6	321.4	1176.1	12.4	1087.9	83.7
West County 2	8760	29.6	1069.8	0.0	5.4	472.0	82.7
West County 3	8760	25.6	602.6	878.3	12.4	1088.0	80.6

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \frac{PH - EPOH_T}{PH - EPOH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2018

1	2				3	4	5	6	7	8	9	
					ACTUAL		TARGET [2]	ADJUST.[3]		ADJUST.[5]	GPIF[6]	ACTUAL
UNIT	HEAT RATE [1] FORMULA				NOF %	ANOHR BTU/KWH	ANOHR AT ACTUAL NOF BTU/KWH	TO ANOHR BTU/KWH	TARGET [4] ANOHR BTU/KWH	ACTUAL ANOHR BTU/KWH	POINTS FROM TABLE	FUEL SAV./(LOSS) $000
Cape Canaveral 3	ANOHR=	-1.00 x	NOF +	6,714	68.1	6,595	6,646	-51	6,637	6,586	0.00	0.0
Manatee 3	ANOHR=	-3.08 x	NOF +	7,152	80.2	6,818	6,905	-87	6,939	6,852	1.15	341.2
Ft. Myers 2	ANOHR=	-0.93 x	NOF +	7,293	72.5	7,139	7,226	-87	7,240	7,153	2.93	756.8
Martin 8	ANOHR=	-3.30 x	NOF +	7,221	72.8	6,939	6,981	-42	7,006	6,964	0.00	0.0
Riviera 5	ANOHR=	-5.71 x	NOF +	7,074	63.5	6,569	6,711	-142	6,601	6,459	10.00	2074.0
St. Lucie 1	ANOHR=	-35.32 x	NOF +	13,902	101.1	10,340	10,331	9	10,441	10,450	0.00	0.0
St. Lucie 2	ANOHR=	-35.10 x	NOF +	13,774	100.5	10,208	10,246	-38	10,303	10,265	0.00	0.0
Turkey Point 3	ANOHR=	-48.63 x	NOF +	15,873	101.6	10,824	10,932	-108	11,044	10,936	2.84	203.9
Turkey Point 4	ANOHR=	-54.37 x	NOF +	16,342	101.4	10,794	10,829	-35	10,970	10,935	0.00	0.0
West County 1	ANOHR=	-6.96 x	NOF +	7,556	69.4	7,216	7,073	143	6,974	7,117	-10.00	(3038.0)
West County 2	ANOHR=	-4.62 x	NOF +	7,284	72.9	6,953	6,947	6	6,885	6,891	0.00	0.0
West County 3	ANOHR=	-5.10 x	NOF +	7,361	67.3	6,960	7,018	-58	6,974	6,916	0.00	0.0

1) THESE FORMULAS ARE AS APPROVED BY THE COMMISSION IN THE PROJECTION FILING AND ARE BASED ON MONTHLY ACTUAL DATA
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.

337.936

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	1,373.0	<- Fuel Sav/(Loss) 1,373.0	89.4	<- Adj. Act. EAF= 90.8	+10	2,708.0		6,530	
+9	1,235.7		89.1		+9	2,437.2		6,533	
+8	1,098.4		88.8		+8	2,166.4		6,536	
+7	961.1		88.5		+7	1,895.6		6,540	
+6	823.8		88.2		+6	1,624.8		6,543	
+5	686.5		87.9		+5	1,354.0		6,546	
+4	549.2		87.6		+4	1,083.2		6,549	
+3	411.9		87.3		+3	812.4		6,552	
+2	274.6		87.0		+2	541.6		6,556	
+1	137.3		86.7		+1	270.8		6,559	
						0	<- Fuel Sav/(Loss)	6,562	<- Adj. Act. HR=6,586
0	0		86.4		0	0		6,637	
						0		6,712	
-1	(137.3)		86.1		-1	(270.8)		6,715	
-2	(274.6)		85.8		-2	(541.6)		6,718	
-3	(411.9)		85.5		-3	(812.4)		6,722	
-4	(549.2)		85.2		-4	(1,083.2)		6,725	
-5	(686.5)		84.9		-5	(1,354.0)		6,728	
-6	(823.8)		84.6		-6	(1,624.8)		6,731	
-7	(961.1)		84.3		-7	(1,895.6)		6,734	
-8	(1,098.4)		84.0		-8	(2,166.4)		6,738	
-9	(1,235.7)		83.7		-9	(2,437.2)		6,741	
-10	(1,373.0)		83.4		-10	(2,708.0)		6,744	
	WEIGHTING FACTOR =		3.01			WEIGHTING FACTOR =		5.93	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	517.0	94.9	+10	2,967.0	6,760
+9	465.3	94.7	+9	2,670.3	6,770
+8	413.6	94.5	+8	2,373.6	6,781
+7	361.9	94.3	+7	2,076.9	6,791
+6	310.2	94.1	+6	1,780.2	6,802
+5	258.5	93.9	+5	1,483.5	6,812
+4	206.8	93.7	+4	1,186.8	6,822
+3	155.1	93.5	+3	890.1	6,833
+2	103.4	93.3	+2	593.4 <- Fuel Sav/(Loss) 341.2	6,843 <- Adj. Act. HR=6,852
+1	51.7	93.1	+1	296.7	6,854
				0	6,864
0	0	92.9	0	0	6,939
				0	7,014
-1	(51.7)	92.7	-1	(296.7)	7,024
-2	(103.4)	92.5	-2	(593.4)	7,035
-3	(155.1)	92.3	-3	(890.1)	7,045
-4	(206.8)	92.1	-4	(1,186.8)	7,056
-5	(258.5)	91.9	-5	(1,483.5)	7,066
-6	(310.2)	91.7	-6	(1,780.2)	7,076
-7	(361.9)	91.5	-7	(2,076.9)	7,087
-8	(413.6)	91.3	-8	(2,373.6)	7,097
-9	(465.3)	91.1	-9	(2,670.3)	7,108
-10	(517.0) <- Fuel Sav/(Loss) (517.0)	90.9 <- Adj. Act. EAF= 89.9	-10	(2,967.0)	7,118
	WEIGHTING FACTOR =	1.13		WEIGHTING FACTOR =	6.50

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	578.0	<- Fuel Sav/(Loss) 578.0	88.4	<- Adj. Act. EAF= 88.7	+10	2,583.0		7,124	
+9	520.2		88.2		+9	2,324.7		7,128	
+8	462.4		87.9		+8	2,066.4		7,132	
+7	404.6		87.7		+7	1,808.1		7,136	
+6	346.8		87.4		+6	1,549.8		7,140	
+5	289.0		87.2		+5	1,291.5		7,145	
+4	231.2		86.9		+4	1,033.2		7,149	
+3	173.4		86.7		+3	774.9	<- Fuel Sav/(Loss) 756.8	7,153	<- Adj. Act. HR=7,153
+2	115.6		86.4		+2	516.6		7,157	
+1	57.8		86.2		+1	258.3		7,161	
						0		7,165	
0	0		85.9		0	0		7,240	
						0		7,315	
-1	(57.8)		85.7		-1	(258.3)		7,319	
-2	(115.6)		85.4		-2	(516.6)		7,323	
-3	(173.4)		85.2		-3	(774.9)		7,327	
-4	(231.2)		84.9		-4	(1,033.2)		7,331	
-5	(289.0)		84.7		-5	(1,291.5)		7,336	
-6	(346.8)		84.4		-6	(1,549.8)		7,340	
-7	(404.6)		84.2		-7	(1,808.1)		7,344	
-8	(462.4)		83.9		-8	(2,066.4)		7,348	
-9	(520.2)		83.7		-9	(2,324.7)		7,352	
-10	(578.0)		83.4		-10	(2,583.0)		7,356	
	WEIGHTING FACTOR =		1.27			WEIGHTING FACTOR =		5.66	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

UNIT: Martin 8

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	657.0	<- Fuel Sav/(Loss) 657.0	83.0	<- Adj. Act. EAF= 83.2	+10	2,743.0		6,849	
+9	591.3		82.8		+9	2,468.7		6,857	
+8	525.6		82.5		+8	2,194.4		6,865	
+7	459.9		82.3		+7	1,920.1		6,874	
+6	394.2		82.0		+6	1,645.8		6,882	
+5	328.5		81.8		+5	1,371.5		6,890	
+4	262.8		81.5		+4	1,097.2		6,898	
+3	197.1		81.3		+3	822.9		6,906	
+2	131.4		81.0		+2	548.6		6,915	
+1	65.7		80.8		+1	274.3		6,923	
						0	<- Fuel Sav/(Loss)	6,931	<- Adj. Act. HR=6,964
0	0		80.5		0	0		7,006	
						0		7,081	
-1	(65.7)		80.3		-1	(274.3)		7,089	
-2	(131.4)		80.0		-2	(548.6)		7,097	
-3	(197.1)		79.8		-3	(822.9)		7,106	
-4	(262.8)		79.5		-4	(1,097.2)		7,114	
-5	(328.5)		79.3		-5	(1,371.5)		7,122	
-6	(394.2)		79.0		-6	(1,645.8)		7,130	
-7	(459.9)		78.8		-7	(1,920.1)		7,138	
-8	(525.6)		78.5		-8	(2,194.4)		7,147	
-9	(591.3)		78.3		-9	(2,468.7)		7,155	
-10	(657.0)		78.0		-10	(2,743.0)		7,163	
	WEIGHTING FACTOR =		1.44			WEIGHTING FACTOR =		6.01	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	1,351.0		87.9	+10	2,074.0	<- Fuel Sav/(Loss) 2,074.0	6,523	<- Adj. Act. HR=6,459
+9	1,215.9		87.7	+9	1,866.6		6,523	
+8	1,080.8		87.4	+8	1,659.2		6,524	
+7	945.7		87.2	+7	1,451.8		6,524	
+6	810.6		86.9	+6	1,244.4		6,524	
+5	675.5		86.7	+5	1,037.0		6,525	
+4	540.4		86.4	+4	829.6		6,525	
+3	405.3		86.2	+3	622.2		6,525	
+2	270.2		85.9	+2	414.8		6,525	
+1	135.1		85.7	+1	207.4		6,526	
					0		6,526	
0	0		85.4	0	0		6,601	
					0		6,676	
-1	(135.1)		85.2	-1	(207.4)		6,676	
-2	(270.2)	<- Fuel Sav/(Loss) (270.2)	84.9	-2	(414.8)	<- Adj. Act. EAF= 84.9	6,677	
-3	(405.3)		84.7	-3	(622.2)		6,677	
-4	(540.4)		84.4	-4	(829.6)		6,677	
-5	(675.5)		84.2	-5	(1,037.0)		6,678	
-6	(810.6)		83.9	-6	(1,244.4)		6,678	
-7	(945.7)		83.7	-7	(1,451.8)		6,678	
-8	(1,080.8)		83.4	-8	(1,659.2)		6,678	
-9	(1,215.9)		83.2	-9	(1,866.6)		6,679	
-10	(1,351.0)		82.9	-10	(2,074.0)		6,679	
	WEIGHTING FACTOR =		2.96		WEIGHTING FACTOR =		4.54	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	3,916.0	<- Fuel Sav/(Loss) 3,916.0	88.0	<- Adj. Act. EAF= 91.3	+10	481.0		10,337	
+9	3,524.4		87.7		+9	432.9		10,340	
+8	3,132.8		87.4		+8	384.8		10,343	
+7	2,741.2		87.1		+7	336.7		10,346	
+6	2,349.6		86.8		+6	288.6		10,349	
+5	1,958.0		86.5		+5	240.5		10,352	
+4	1,566.4		86.2		+4	192.4		10,354	
+3	1,174.8		85.9		+3	144.3		10,357	
+2	783.2		85.6		+2	96.2		10,360	
+1	391.6		85.3		+1	48.1		10,363	
						0		10,366	
0	0		85.0		0	0	<- Fuel Sav/(Loss)	10,441	<- Adj. Act. HR=10.450
						0		10,516	
-1	(391.6)		84.7		-1	(48.1)		10,519	
-2	(783.2)		84.4		-2	(96.2)		10,522	
-3	(1,174.8)		84.1		-3	(144.3)		10,525	
-4	(1,566.4)		83.8		-4	(192.4)		10,528	
-5	(1,958.0)		83.5		-5	(240.5)		10,531	
-6	(2,349.6)		83.2		-6	(288.6)		10,533	
-7	(2,741.2)		82.9		-7	(336.7)		10,536	
-8	(3,132.8)		82.6		-8	(384.8)		10,539	
-9	(3,524.4)		82.3		-9	(432.9)		10,542	
-10	(3,916.0)		82.0		-10	(481.0)		10,545	
	WEIGHTING FACTOR =		8.58			WEIGHTING FACTOR =		1.06	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	3,241.0	<- Fuel Sav/(Loss) 3,241.0	88.1	<- Adj. Act. EAF= 88.9	+10	357.0		10,221	
+9	2,916.9		87.8		+9	321.3		10,222	
+8	2,592.8		87.5		+8	285.6		10,222	
+7	2,268.7		87.2		+7	249.9		10,223	
+6	1,944.6		86.9		+6	214.2		10,224	
+5	1,620.5		86.6		+5	178.5		10,225	
+4	1,296.4		86.3		+4	142.8		10,225	
+3	972.3		86.0		+3	107.1		10,226	
+2	648.2		85.7		+2	71.4		10,227	
+1	324.1		85.4		+1	35.7		10,227	
						0	<- Fuel Sav/(Loss)	10,228	<- Adj. Act. HR=10.265
0	0		85.1		0	0		10,303	
						0		10,378	
-1	(324.1)		84.8		-1	(35.7)		10,379	
-2	(648.2)		84.5		-2	(71.4)		10,379	
-3	(972.3)		84.2		-3	(107.1)		10,380	
-4	(1,296.4)		83.9		-4	(142.8)		10,381	
-5	(1,620.5)		83.6		-5	(178.5)		10,382	
-6	(1,944.6)		83.3		-6	(214.2)		10,382	
-7	(2,268.7)		83.0		-7	(249.9)		10,383	
-8	(2,592.8)		82.7		-8	(285.6)		10,384	
-9	(2,916.9)		82.4		-9	(321.3)		10,384	
-10	(3,241.0)		82.1		-10	(357.0)		10,385	
	WEIGHTING FACTOR =		7.10			WEIGHTING FACTOR =		0.78	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	3,119.0	<- Fuel Sav/(Loss) 3,119.0	85.1	<- Adj. Act. EAF= 88.5	+10	718.0		10,853	
+9	2,807.1		84.8		+9	646.2		10,865	
+8	2,495.2		84.5		+8	574.4		10,876	
+7	2,183.3		84.2		+7	502.6		10,888	
+6	1,871.4		83.9		+6	430.8		10,899	
+5	1,559.5		83.6		+5	359.0		10,911	
+4	1,247.6		83.3		+4	287.2		10,923	
+3	935.7		83.0		+3	215.4	<- Fuel Sav/(Loss) 203.9	10,934	<- Adj. Act. HR=10,936
+2	623.8		82.7		+2	143.6		10,946	
+1	311.9		82.4		+1	71.8		10,957	
						0		10,969	
0	0		82.1		0	0		11,044	
						0		11,119	
-1	(311.9)		81.8		-1	(71.8)		11,131	
-2	(623.8)		81.5		-2	(143.6)		11,142	
-3	(935.7)		81.2		-3	(215.4)		11,154	
-4	(1,247.6)		80.9		-4	(287.2)		11,165	
-5	(1,559.5)		80.6		-5	(359.0)		11,177	
-6	(1,871.4)		80.3		-6	(430.8)		11,189	
-7	(2,183.3)		80.0		-7	(502.6)		11,200	
-8	(2,495.2)		79.7		-8	(574.4)		11,212	
-9	(2,807.1)		79.4		-9	(646.2)		11,223	
-10	(3,119.0)		79.1		-10	(718.0)		11,235	
	WEIGHTING FACTOR =		6.83			WEIGHTING FACTOR =		1.57	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	3,597.0	<- Fuel Sav/(Loss) 3,597.0	96.6	<- Adj. Act. EAF= 100.0	+10	863.0		10,688	
+9	3,237.3		96.3		+9	776.7		10,709	
+8	2,877.6		96.0		+8	690.4		10,729	
+7	2,517.9		95.7		+7	604.1		10,750	
+6	2,158.2		95.4		+6	517.8		10,771	
+5	1,798.5		95.1		+5	431.5		10,792	
+4	1,438.8		94.8		+4	345.2		10,812	
+3	1,079.1		94.5		+3	258.9		10,833	
+2	719.4		94.2		+2	172.6		10,854	
+1	359.7		93.9		+1	86.3		10,874	
						0	<- Fuel Sav/(Loss)	10,895	<- Adj. Act. HR=10,935
0	0		93.6		0	0		10,970	
						0		11,045	
-1	(359.7)		93.3		-1	(86.3)		11,066	
-2	(719.4)		93.0		-2	(172.6)		11,086	
-3	(1,079.1)		92.7		-3	(258.9)		11,107	
-4	(1,438.8)		92.4		-4	(345.2)		11,128	
-5	(1,798.5)		92.1		-5	(431.5)		11,149	
-6	(2,158.2)		91.8		-6	(517.8)		11,169	
-7	(2,517.9)		91.5		-7	(604.1)		11,190	
-8	(2,877.6)		91.2		-8	(690.4)		11,211	
-9	(3,237.3)		90.9		-9	(776.7)		11,231	
-10	(3,597.0)		90.6		-10	(863.0)		11,252	
	WEIGHTING FACTOR =		7.88			WEIGHTING FACTOR =		1.89	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	1,297.0	<- Fuel Sav/(Loss) 1.297.0	82.1	<- Adj. Act. EAF= 83.7	+10	3,038.0		6,844	
+9	1,167.3		81.8		+9	2,734.2		6,850	
+8	1,037.6		81.5		+8	2,430.4		6,855	
+7	907.9		81.2		+7	2,126.6		6,861	
+6	778.2		80.9		+6	1,822.8		6,866	
+5	648.5		80.6		+5	1,519.0		6,872	
+4	518.8		80.3		+4	1,215.2		6,877	
+3	389.1		80.0		+3	911.4		6,883	
+2	259.4		79.7		+2	607.6		6,888	
+1	129.7		79.4		+1	303.8		6,894	
						0		6,899	
0	0		79.1		0	0		6,974	
						0		7,049	
-1	(129.7)		78.8		-1	(303.8)		7,055	
-2	(259.4)		78.5		-2	(607.6)		7,060	
-3	(389.1)		78.2		-3	(911.4)		7,066	
-4	(518.8)		77.9		-4	(1,215.2)		7,071	
-5	(648.5)		77.6		-5	(1,519.0)		7,077	
-6	(778.2)		77.3		-6	(1,822.8)		7,082	
-7	(907.9)		77.0		-7	(2,126.6)		7,088	
-8	(1,037.6)		76.7		-8	(2,430.4)		7,093	
-9	(1,167.3)		76.4		-9	(2,734.2)		7,099	
-10	(1,297.0)		76.1		-10	(3,038.0)	<- Fuel Sav/(Loss) (3,038.0)	7,104	<- Adj. Act. HR=7,117
	WEIGHTING FACTOR =	2.84				WEIGHTING FACTOR =		6.66	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	1,252.0	91.8	+10	2,745.0	6,778
+9	1,126.8	91.6	+9	2,470.5	6,781
+8	1,001.6	91.3	+8	2,196.0	6,784
+7	876.4	91.1	+7	1,921.5	6,788
+6	751.2	90.8	+6	1,647.0	6,791
+5	626.0	90.6	+5	1,372.5	6,794
+4	500.8	90.3	+4	1,098.0	6,797
+3	375.6	90.1	+3	823.5	6,800
+2	250.4	89.8	+2	549.0	6,804
+1	125.2	89.6	+1	274.5	6,807
				0	6,810
0	0	89.3	0	0 <- Fuel Sav/(Loss)	6,885 <- Adj. Act. HR=6,891
				0	6,960
-1	(125.2)	89.1	-1	(274.5)	6,963
-2	(250.4)	88.8	-2	(549.0)	6,966
-3	(375.6)	88.6	-3	(823.5)	6,970
-4	(500.8)	88.3	-4	(1,098.0)	6,973
-5	(626.0)	88.1	-5	(1,372.5)	6,976
-6	(751.2)	87.8	-6	(1,647.0)	6,979
-7	(876.4)	87.6	-7	(1,921.5)	6,982
-8	(1,001.6)	87.3	-8	(2,196.0)	6,986
-9	(1,126.8)	87.1	-9	(2,470.5)	6,989
-10	(1,252.0) <- Fuel Sav/(Loss) (1,252.0)	86.8 <- Adj. Act. EAF= 82.7	-10	(2,745.0)	6,992
	WEIGHTING FACTOR =	2.74		WEIGHTING FACTOR =	6.01

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2018

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	1,075.0	<- Fuel Sav/(Loss) 1,075.0	82.9	+10	2,397.0		6,870	
+9	967.5		82.7	+9	2,157.3		6,873	
+8	860.0		82.4	+8	1,917.6		6,876	
+7	752.5		82.2	+7	1,677.9		6,879	
+6	645.0		81.9	+6	1,438.2		6,882	
+5	537.5		81.7	+5	1,198.5		6,885	
+4	430.0		81.4	+4	958.8		6,887	
+3	322.5		81.2	+3	719.1		6,890	
+2	215.0		80.9	+2	479.4		6,893	
+1	107.5		80.7	+1	239.7		6,896	
					0	<- Fuel Sav/(Loss)	6,899	<- Adj. Act. HR=6,916
0	0	<- Fuel Sav/(Loss) 1,075.0	80.4	<- Adj. Act. EAF= 80.6	0	0	6,974	
						0	7,049	
-1	(107.5)		80.2	-1	(239.7)		7,052	
-2	(215.0)		79.9	-2	(479.4)		7,055	
-3	(322.5)		79.7	-3	(719.1)		7,058	
-4	(430.0)		79.4	-4	(958.8)		7,061	
-5	(537.5)		79.2	-5	(1,198.5)		7,064	
-6	(645.0)		78.9	-6	(1,438.2)		7,066	
-7	(752.5)		78.7	-7	(1,677.9)		7,069	
-8	(860.0)		78.4	-8	(1,917.6)		7,072	
-9	(967.5)		78.2	-9	(2,157.3)		7,075	
-10	(1,075.0)		77.9	-10	(2,397.0)		7,078	
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	WEIGHTING FACTOR =		2.36		WEIGHTING FACTOR =		5.25	

ACTUAL PLANNED OUTAGES

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2018

PLANT/UNIT	ACTUAL PLANNED OUTAGE DATE	REASON FOR OUTAGE
Cape Canaveral 3	5/15/18-6/7/18	CT-31 reliability outage
Manatee 3	NONE	N/A
Ft. Myers 2	11/13/18-12/15/18; 2/22/18-4/12/18 2/14/18-4/7/18; 11/18/18-12/31/18 3/4/18-3/18/18; 3/5/18-3/19/18	CT-2A 3SAR upgrade; CT-2B 3SAR upgrade CT-2D 3SAR upgrade; CT-2E 3SAR upgrade ST1 generator minor; ST2 generator minor
Martin 8	11/17/18-12/11/18; 10/12/18-12/12/18 10/20/18-12/16/18 & 12/18-19/18 11/17/18-12/11/18	CT-8A & CT-8B EHD upgrades; CT-8C 3SAR and EHD upgrades CT-8D 3SAR and EHD upgrades 8ST steam valve planned outage
Riviera 5	11/2/18-12/16/18; 9/14/18-11/2/18	CT-52 Major overhaul; CT-53 upgrade and Major overhaul
St. Lucie 1	3/10/18-4/13/18	Main Steam Safety Valve (MSSV) testing & Refueling outage
St. Lucie 2	5/3/18-5/3/18; 8/26/18-10/5/18	Turbine valve; refueling outage
Turkey Point 3	9/29/18-11/12/18	Refueling
Turkey Point 4	8/13/18-8/15/18	Downpower to repair 4B Steam Generator Fuel Pump
West County 1	11/9/18-12/20/18; 10/30/18-12/11/18 4/10/18-5/20/18; 11/14/18-12/9/18	CT-1A Hot Gas Path (HGP) outage and tuning; CT-1B HGP/turbine inspection CT-1C Hot Gas Path (HGP) outage;CT-1C reliability and block outage
West County 2	NONE	N/A
West County 3	4/29/18-6/18/18; 6/18-20/18 & 6/22/18 2/19/18-4/18/18	CT-3A Major overhaul; CT-3A testing CT-3C Major overhaul and Kai upgrade

WITNESS: CHARLES R. ROTE

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2020

SEPTEMBER 3, 2019

CRR-2
DOCKET NO. 20190001-EI
FPL Witness: Charles R. Rote
Exhibit No.: _____
Pages 1 - 34

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 27
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: C. R. Rote CRR-2

EXHIBIT INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2020

EXHIBIT	PAGE NUMBER	TITLE
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 - 7.201.021	Estimated Unit Performance Data
	7.201.022 - 7.201.033	Unit FOF and MOF vs Time Graphs
	7.201.034	Planned Outages Schedule (Estimated)

PROJECTED SYSTEM NET GENERATION
JANUARY THROUGH DECEMBER, 2020

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
Okeechobee	1,652	8,448	12,681,808	90.9	10.3	10.3	194,448
Port Everglades 5	1,264	8,496	9,363,506	87.2	7.6	17.9	147,673
West County 2	1,264	8,592	9,256,341	85.2	7.5	25.5	148,128
West County 3	1,247	8,352	8,604,003	82.6	7.0	32.5	139,002
St. Lucie 1	981	8,784	8,482,708	98.4	6.9	39.4	41,562
Ft. Myers 2	1,774	8,616	8,268,224	54.1	6.7	46.1	147,919
Riviera 5	1,309	8,112	8,183,308	77.1	6.7	52.8	134,109
Cape Canaveral 3	1,309	8,112	7,878,890	74.2	6.4	59.2	128,819
West County 1	1,264	6,967	7,154,427	81.2	5.8	65.0	113,147
St. Lucie 2	840	8,088	6,679,331	98.3	5.4	70.4	31,114
Turkey Point 3	837	8,088	6,677,635	98.6	5.4	75.9	37,197
Turkey Point 4	821	7,824	6,373,199	99.2	5.2	81.1	35,709
Manatee 3	1,238	4,758	4,046,757	68.7	3.3	84.4	71,290
Turkey Point 5	1,248	4,571	3,603,940	63.2	2.9	87.3	66,743
Martin 8	1,231	3,683	3,539,206	78.1	2.9	90.2	61,978
Sanford 5	1,164	3,455	2,566,600	63.8	2.1	92.3	47,712
Sanford 4	1,164	2,747	2,115,109	66.1	1.7	94.0	39,273
Scherer 4	625	7,560	1,901,868	40.3	1.5	95.5	55,244
Martin 4	476	1,339	445,708	69.9	0.4	95.9	9,091
Martin 3	476	1,612	522,708	68.1	0.4	96.3	10,463
Horizon PV Solar	74.5	4,514	173,550	51.6	0.1	96.5	0
Hammock PV Solar	74.5	4,514	172,665	51.3	0.1	96.6	0
Barefoot PV Solar	74.5	4,485	172,637	51.7	0.1	96.7	0
Coral Farms PV Solar	74.5	4,514	172,464	51.3	0.1	96.9	0
Interstate PV Solar	74.5	4,485	172,304	51.6	0.1	97.0	0
Wildflower PV Solar	74.5	4,514	171,746	51.1	0.1	97.2	0
Miami-Dade PV Solar	74.5	4,485	171,664	51.4	0.1	97.3	0
Sunshine Gateway PV Solar	74.5	4,544	171,115	50.5	0.1	97.4	0
Loggerhead PV Solar	74.5	4,485	169,744	50.8	0.1	97.6	0
Manatee PV Solar	74.5	4,821	169,129	47.1	0.1	97.7	0
Blue Cypress PV Solar	74.5	4,485	169,011	50.6	0.1	97.8	0
Indian River PV Solar	74.5	4,485	168,461	50.4	0.1	98.0	0
Citrus PV Solar	74.5	4,790	168,076	47.1	0.1	98.1	0
Pioneer Trail PV Solar	74.5	4,485	167,634	50.2	0.1	98.3	0
Babcock PV Solar	74.5	4,852	166,927	46.2	0.1	98.4	0
ST Project 1 Site 3	74.5	4,234	166,107	52.7	0.1	98.5	0
ST Project 2 Site 1	74.5	4,234	161,642	51.2	0.1	98.7	0
ST Project 2 Site 2	74.5	4,173	148,228	47.7	0.1	98.8	0
ST Project 2 Site 3	74.5	4,173	148,083	47.6	0.1	98.9	0
ST Project 1 Site 1	74.5	4,174	145,267	46.7	0.1	99.0	0
ST Project 1 Site 2	74.5	4,173	142,779	45.9	0.1	99.1	0
Southfork PV Solar	74.5	3,032	136,615	60.5	0.1	99.2	0
Echo River PV Solar	74.5	3,185	135,980	57.3	0.1	99.4	0
Okeechobee PV Solar	74.5	3,032	118,605	52.5	0.1	99.5	0
Hibiscus PV Solar	74.5	3,032	114,544	50.7	0.1	99.5	0
Manatee 2	790	400	101,412	32.1	0.1	99.6	3,191
Manatee 1	790	382	95,274	31.6	0.1	99.7	3,106
Lauderdale 6C	215	364	73,474	93.9	0.1	99.8	1,888
Lauderdale 6B	215	373	75,205	93.8	0.1	99.8	1,933
Lauderdale 6A	215	392	79,113	93.9	0.1	99.9	2,036
DeSoto PV Solar	25	4,698	48,071	40.9	0.0	99.9	0
Ft. Myers 3C	215	172	34,031	92.0	0.0	100.0	891
Ft. Myers 3D	215	180	35,548	91.9	0.0	100.0	926
Space Coast PV Solar	10	4,727	17,441	36.9	0.0	100.0	0
Ft. Myers 3A	190	-	-	0.0	0.0	100.0	0
Ft. Myers 3B	190	-	-	0.0	0.0	100.0	0
Lauderdale 6D	215	-	-	0.0	0.0	100.0	0
Lauderdale 6E	215	-	-	0.0	0.0	100.0	0
Total	**27,547**		**122,879,822**		**100.0**		**1,674,592**

UNITS TO BE USED TO DETERMINE THE GENERATING PERFORMANCE INCENTIVE FACTOR

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2020

Cape Canaveral 3

Ft. Myers 2

Manatee 3

Port Everglades 5

Riviera 5

St. Lucie 1

St. Lucie 2

Turkey Point 3

Turkey Point 4

West County 1

West County 2

West County 3

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

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	11,340	5,670
+ 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 (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2020

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	20,791,364,329	
LINE 2	MONTH OF JANUARY	2020	$	21,021,204,354	
LINE 3	MONTH OF FEBRUARY	2020	$	21,197,709,173	
LINE 4	MONTH OF MARCH	2020	$	21,996,408,965	
LINE 5	MONTH OF APRIL	2020	$	22,201,202,121	
LINE 6	MONTH OF MAY	2020	$	22,441,137,172	
LINE 7	MONTH OF JUNE	2020	$	22,714,553,011	
LINE 8	MONTH OF JULY	2020	$	23,005,020,564	
LINE 9	MONTH OF AUGUST	2020	$	23,732,142,832	
LINE 10	MONTH OF SEPTEMBER	2020	$	23,919,620,409	
LINE 11	MONTH OF OCTOBER	2020	$	24,114,759,902	
LINE 12	MONTH OF NOVEMBER	2020	$	24,326,731,603	
LINE 13	MONTH OF DECEMBER	2020	$	24,441,000,101	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	22,761,758,041	
LINE 15	25 BASIS POINTS			0.0025	
LINE 16	REVENUE EXPANSION FACTOR			74.6012%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	76,278,123	
LINE 18	JURISDICTIONAL SALES			110,803,324,036	KWH
LINE 19	TOTAL SALES			116,710,071,525	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			94.94%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$	72,418,450	
LINE 22	INCENTIVE CAP (50 PECENT 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.

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2020

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 3	1.24	83.4	85.9	80.9	469	-469
Manatee 3	0.42	91.3	93.8	88.8	158	-158
Ft. Myers 2	0.61	90.1	92.6	87.6	232	-232
Port Everglades 5	2.17	81.8	84.8	78.8	822	-822
Riviera 5	1.18	84.7	87.2	82.2	446	-446
St. Lucie 1	9.86	87.4	90.9	83.9	3,728	-3,728
St. Lucie 2	6.81	85.7	88.7	82.7	2,576	-2,576
Turkey Point 3	6.36	85.7	88.7	82.7	2,403	-2,403
Turkey Point 4	5.95	82.7	85.7	79.7	2,250	-2,250
West County 1	1.31	68.5	71.0	66.0	496	-496
West County 2	1.62	90.2	92.7	87.7	614	-614
West County 3	1.61	85.3	88.3	82.3	608	-608
	39.14				14,802	-14,802

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2020

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	NOF	ANOHR RANGE BTU/KWH	BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 3	6.29	6,615	74.2	6,493	6,737	2,376	-2,376
Manatee 3	3.34	6,880	68.7	6,758	7,002	1,264	-1,264
Ft. Myers 2	6.02	7,342	54.1	7,229	7,455	2,277	-2,277
Port Everglades 5	10.18	6,525	87.2	6,355	6,695	3,847	-3,847
Riviera 5	6.32	6,567	77.1	6,450	6,684	2,389	-2,389
St. Lucie 1	1.09	10,421	98.4	10,317	10,525	413	-413
St. Lucie 2	0.74	10,262	98.3	10,169	10,355	278	-278
Turkey Point 3	1.76	11,228	98.6	11,038	11,418	661	-661
Turkey Point 4	1.48	10,865	99.2	10,695	11,035	561	-561
West County 1	6.70	7,060	81.2	6,902	7,218	2,532	-2,532
West County 2	8.28	6,918	85.2	6,772	7,064	3,126	-3,126
West County 3	8.66	6,921	82.6	6,758	7,084	3,274	-3,274
	60.86					22,998	-22,998

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2020

				ANOHR Equation					
Plant/Unit	ANOHR	NOF	MW	a coef.	b coef.	Bounds	First	Last	Exclusions
Cape Canaveral 3	6,615	74.2	1309	6705	-1.21	122	07-16	06-19	5/18
Manatee 3	6,880	68.7	1238	7039	-2.32	122	07-16	06-19	5/17, 6/17, 11/17, 12/17
Ft. Myers 2	7,342	54.1	1774	7768	-7.88	113	07-16	06-19	12/17, 12/18, 3/19, 4/19, 5/19, 6/19
Port Everglades 5	6,525	87.2	1264	7434	-10.43	170	07-16	06-19	3/17, 8/17
Riviera 5	6,567	77.1	1309	6909	-4.44	117	07-16	06-19	3/19
St. Lucie 1	10,421	98.4	981	13876	-35.11	104	07-16	06-19	8/16, 10/16, 5/19
St. Lucie 2	10,262	98.3	840	12239	-20.11	93	07-16	06-19	9/18
Turkey Point 3	11,228	98.6	837	22907	-118.45	190	07-16	06-19	4/17, 10/18, 11/18, 1/19, 5/19, 6/19
Turkey Point 4	10,865	99.2	821	13728	-28.86	170	07-16	06-19	10/17
West County 1	7,060	81.2	1264	7575	-6.34	158	07-16	06-19	4/17, 11/18
West County 2	6,918	85.2	1264	7502	-6.85	146	07-16	06-19	4/19, 6/19
West County 3	6,921	82.6	1247	7442	-6.31	163	07-16	06-19	8/16

DERIVATION OF WEIGHTING FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2020

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	1,674,592	1,674,123	469	1.24
Cape Canaveral 3	ANOHR	1,674,592	1,672,216	2,376	6.29
Manatee 3	EAF	1,674,592	1,674,434	158	0.42
Manatee 3	ANOHR	1,674,592	1,673,328	1,264	3.34
Ft. Myers 2	EAF	1,674,592	1,674,360	232	0.61
Ft. Myers 2	ANOHR	1,674,592	1,672,315	2,277	6.02
Port Everglades 5	EAF	1,674,592	1,673,770	822	2.17
Port Everglades 5	ANOHR	1,674,592	1,670,745	3,847	10.18
Riviera 5	EAF	1,674,592	1,674,146	446	1.18
Riviera 5	ANOHR	1,674,592	1,672,203	2,389	6.32
St. Lucie 1	EAF	1,674,592	1,670,864	3,728	9.86
St. Lucie 1	ANOHR	1,674,592	1,674,179	413	1.09
St. Lucie 2	EAF	1,674,592	1,672,016	2,576	6.81
St. Lucie 2	ANOHR	1,674,592	1,674,314	278	0.74
Turkey Point 3	EAF	1,674,592	1,672,189	2,403	6.36
Turkey Point 3	ANOHR	1,674,592	1,673,931	661	1.76
Turkey Point 4	EAF	1,674,592	1,672,342	2,250	5.95
Turkey Point 4	ANOHR	1,674,592	1,674,031	561	1.48
West County 1	EAF	1,674,592	1,674,096	496	1.31
West County 1	ANOHR	1,674,592	1,672,060	2,532	6.70
West County 2	EAF	1,674,592	1,673,978	614	1.62
West County 2	ANOHR	1,674,592	1,671,466	3,126	8.28
West County 3	EAF	1,674,592	1,673,984	608	1.61
West County 3	ANOHR	1,674,592	1,671,318	3,274	8.66
	TOTAL			37,800	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

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	Cape Canaveral 3	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	91.9	70.7	11.8	91.9	91.9	91.9
2	EPOF (%)	0.0	23.0	87.1	0.0	0.0	0.0
3	EUOF (%)	8.1	6.3	1.1	8.1	8.1	8.1
4	EUOR (%)	8.1	6.5	8.1	8.1	8.1	8.1
5	PH	744	696	744	720	744	720
6	SH	744	672	96	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	24	648	0	0	0
9	POH	0	24	648	0	0	0
10	FOH & EFOH	16	12	2	16	16	16
11	MOH & EMOH	44	32	6	43	44	43
12	Oper Mbtu	4,311,283	3,143,310	536,807	4,842,227	4,933,550	5,248,375
13	Net Gen (MWH)	650,858	473,390	81,003	732,450	746,151	794,847
14	ANOHR (Btu/KWH)	6,624	6,640	6,627	6,611	6,612	6,603
15	NOF (%)	66.8	53.8	64.5	77.7	76.6	84.3
16	NSC (MW)	1,309	1,309	1,309	1,309	1,309	1,309
17	ANOHR Equation	-1.21 x NOF + 6705					

	Cape Canaveral 3	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	91.9	91.9	91.9	91.9	91.9	91.9	83.4
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	9.2
3	EUOF (%)	8.1	8.1	8.1	8.1	8.1	8.1	7.4
4	EUOR (%)	8.1	8.1	8.1	8.1	8.1	8.1	8.0
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	744	720	744	8,112
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	672
9	POH	0	0	0	0	0	0	672
10	FOH & EFOH	16	16	16	16	16	16	176
11	MOH & EMOH	44	44	43	44	43	44	474
12	Oper Mbtu	5,127,282	5,051,091	5,295,491	4,564,337	4,725,742	4,331,632	52,118,857
13	Net Gen (MWH)	775,803	764,159	802,104	689,581	714,614	653,930	7,878,890
14	ANOHR (Btu/KWH)	6,609	6,610	6,602	6,619	6,613	6,624	6,615
15	NOF (%)	79.7	78.5	85.1	70.8	75.8	67.1	74.2
16	NSC (MW)	1,309	1,309	1,309	1,309	1,309	1,309	1,309
17	ANOHR Equation	-1.21 x NOF + 6705						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	Ft. Myers 2	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	94.3	64.0	94.3	94.3	94.3	94.3
2	EPOF (%)	0.0	32.2	0.0	0.0	0.0	0.0
3	EUOF (%)	5.7	3.8	5.7	5.7	5.7	5.7
4	EUOR (%)	5.7	5.1	5.7	5.7	5.7	5.7
5	PH	744	696	744	720	744	720
6	SH	744	528	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	168	0	0	0	0
9	POH	0	168	0	0	0	0
10	FOH & EFOH	16	10	16	15	16	15
11	MOH & EMOH	26	17	26	26	26	26
12	Oper Mbtu	4,319,523	3,202,445	5,260,930	5,083,180	5,442,186	5,405,257
13	Net Gen (MWH)	582,146	432,529	716,748	692,437	743,062	739,231
14	ANOHR (Btu/KWH)	7,420	7,404	7,340	7,341	7,324	7,312
15	NOF (%)	44.1	46.2	54.3	54.2	56.3	57.9
16	NSC (MW)	1,774	1,774	1,774	1,774	1,774	1,774
17	ANOHR Equation	-7.88 x NOF + 7768					

	Ft. Myers 2	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	94.3	94.3	79.6	94.3	87.0	94.3	90.1
2	EPOF (%)	0.0	0.0	15.6	0.0	7.8	0.0	4.5
3	EUOF (%)	5.7	5.7	4.8	5.7	5.2	5.7	5.4
4	EUOR (%)	5.7	5.7	4.8	5.7	5.2	5.7	5.5
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	744	720	744	8,616
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	168
9	POH	0	0	0	0	0	0	168
10	FOH & EFOH	16	16	13	16	14	16	176
11	MOH & EMOH	26	26	22	26	24	26	299
12	Oper Mbtu	5,705,724	5,711,886	5,165,747	5,866,480	4,869,854	4,637,916	60,705,301
13	Net Gen (MWH)	781,392	782,343	704,356	805,061	661,665	627,254	8,268,224
14	ANOHR (Btu/KWH)	7,302	7,301	7,334	7,287	7,360	7,394	7,342
15	NOF (%)	59.2	59.3	55.1	61.0	51.8	47.5	54.1
16	NSC (MW)	1,774	1,774	1,774	1,774	1,774	1,774	1,774
17	ANOHR Equation	-7.88 x NOF + 7768						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	Manatee 3	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	94.0	94.0	94.0	94.0	94.0	94.0
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	6.0	6.0	6.0	6.0	6.0	6.0
4	EUOR (%)	24.5	17.0	8.4	8.5	11.8	9.2
5	PH	744	696	744	720	744	720
6	SH	181	244	531	506	375	469
7	RSH	563	452	213	214	369	251
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	29	27	29	28	29	28
12	Oper Mbtu	853,944	1,363,984	2,834,558	2,844,600	2,360,044	2,998,145
13	Net Gen (MWH)	123,563	198,052	411,163	413,099	343,679	436,729
14	ANOHR (Btu/KWH)	6,911	6,887	6,894	6,886	6,867	6,865
15	NOF (%)	55.1	65.6	62.5	65.9	74.0	75.2
16	NSC (MW)	1,238	1,238	1,238	1,238	1,238	1,238
17	ANOHR Equation	-2.32 x NOF + 7039					

	Manatee 3	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	94.0	94.0	94.0	94.0	61.1	94.0	91.3
2	EPOF (%)	0.0	0.0	0.0	0.0	35.0	0.0	2.9
3	EUOF (%)	6.0	6.0	6.0	6.0	3.9	6.0	5.8
4	EUOR (%)	9.1	9.0	7.7	6.3	17.4	101.0	10.7
5	PH	744	744	720	744	720	744	8,784
6	SH	487	495	555	710	161	44	4,758
7	RSH	257	249	165	34	391	700	3858
8	UH	0	0	0	0	168	0	168
9	POH	0	0	0	0	168	0	168
10	FOH & EFOH	15	15	15	15	10	15	176
11	MOH & EMOH	29	29	28	29	18	29	334
12	Oper Mbtu	3,047,799	3,009,611	3,353,790	4,026,940	923,671	219,223	27,841,688
13	Net Gen (MWH)	443,768	437,889	487,895	584,971	134,196	31,753	4,046,757
14	ANOHR (Btu/KWH)	6,868	6,873	6,874	6,884	6,883	6,904	6,880
15	NOF (%)	73.6	71.5	71.0	66.6	67.3	58.3	68.7
16	NSC (MW)	1,238	1,238	1,238	1,238	1,238	1,238	1,238
17	ANOHR Equation	-2.32 x NOF + 7039						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	Port Everglades 5	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	88.2	88.2	88.2	69.0	42.0	77.8
2	EPOF (%)	0.0	0.0	0.0	21.7	52.4	11.7
3	EUOF (%)	11.8	11.8	11.8	9.3	5.6	10.5
4	EUOR (%)	11.8	11.8	11.8	9.3	9.2	10.5
5	PH	744	696	744	720	744	720
6	SH	744	696	744	720	456	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	288	0
9	POH	0	0	0	0	288	0
10	FOH & EFOH	41	38	41	31	19	35
11	MOH & EMOH	47	44	47	36	22	40
12	Oper Mbtu	5,575,185	5,211,515	5,621,699	4,032,248	2,525,471	4,732,019
13	Net Gen (MWH)	860,368	804,122	868,887	597,370	373,701	715,455
14	ANOHR (Btu/KWH)	6,480	6,481	6,470	6,750	6,758	6,614
15	NOF (%)	91.5	91.4	92.4	65.6	64.8	78.6
16	NSC (MW)	1,264	1,264	1,264	1,264	1,264	1,264
17	ANOHR Equation	-10.43 x NOF + 7434					

	Port Everglades 5	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	88.2	88.2	88.2	88.2	88.2	88.2	81.8
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	7.2
3	EUOF (%)	11.8	11.8	11.8	11.8	11.8	11.8	11
4	EUOR (%)	11.8	11.8	11.8	11.8	11.8	11.8	11.4
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	744	720	744	8,496
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	288
9	POH	0	0	0	0	0	0	288
10	FOH & EFOH	41	41	40	41	40	41	448
11	MOH & EMOH	47	47	46	47	46	47	518
12	Oper Mbtu	5,647,915	5,670,852	5,471,336	5,497,277	5,413,909	5,591,860	61,096,877
13	Net Gen (MWH)	873,614	877,705	846,432	846,386	836,125	863,341	9,363,506
14	ANOHR (Btu/KWH)	6,465	6,461	6,464	6,495	6,475	6,477	6,525
15	NOF (%)	92.9	93.3	93.0	90.0	91.9	91.8	87.2
16	NSC (MW)	1,264	1,264	1,264	1,264	1,264	1,264	1,264
17	ANOHR Equation	-10.43 x NOF + 7434						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	Riviera 5	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	91.8	91.8	91.8	91.8	91.8	91.8
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	8.2	8.2	8.2	8.2	8.2	8.2
4	EUOR (%)	8.2	8.2	8.2	8.2	8.2	8.2
5	PH	744	696	744	720	744	720
6	SH	744	696	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	45	42	45	44	45	44
12	Oper Mbtu	4,347,962	4,104,321	5,152,446	4,841,526	4,746,246	5,032,757
13	Net Gen (MWH)	657,885	621,302	786,633	737,925	721,314	768,712
14	ANOHR (Btu/KWH)	6,609	6,606	6,550	6,561	6,580	6,547
15	NOF (%)	67.6	68.2	80.8	78.3	74.1	81.6
16	NSC (MW)	1,309	1,309	1,309	1,309	1,309	1,309
17	ANOHR Equation	-4.44 x NOF + 6909					

	Riviera 5	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	91.8	91.8	91.8	41.5	58.1	91.8	84.7
2	EPOF (%)	0.0	0.0	0.0	54.8	36.7	0.0	7.7
3	EUOF (%)	8.2	8.2	8.2	3.7	5.2	8.2	7.6
4	EUOR (%)	8.2	8.2	8.2	8.2	8.2	8.2	8.2
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	336	456	744	8,112
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	408	264	0	672
9	POH	0	0	0	408	264	0	672
10	FOH & EFOH	16	16	16	7	10	16	176
11	MOH & EMOH	45	45	44	20	28	45	492
12	Oper Mbtu	5,426,378	5,323,096	5,245,255	2,129,423	2,954,351	4,414,318	53,739,784
13	Net Gen (MWH)	830,992	814,178	803,132	323,473	449,331	668,431	8,183,308
14	ANOHR (Btu/KWH)	6,530	6,538	6,531	6,583	6,575	6,604	6,567
15	NOF (%)	85.3	83.6	85.2	73.5	75.3	68.6	77.1
16	NSC (MW)	1,309	1,309	1,309	1,309	1,309	1,309	1,309
17	ANOHR Equation	-4.44 x NOF + 6909						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	St. Lucie 1	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	87.4	87.4	87.4	87.4	87.4	87.4
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	12.6	12.6	12.6	12.6	12.6	12.6
4	EUOR (%)	12.6	12.6	12.6	12.6	12.6	12.6
5	PH	744	696	744	720	744	720
6	SH	744	696	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	70	65	70	68	70	68
11	MOH & EMOH	24	22	24	23	24	23
12	Oper Mbtu	7,551,631	7,064,421	7,551,631	7,199,052	7,439,023	7,199,052
13	Net Gen (MWH)	728,079	681,105	728,079	688,707	711,664	688,707
14	ANOHR (Btu/KWH)	10,372	10,372	10,372	10,453	10,453	10,453
15	NOF (%)	99.8	99.8	99.8	97.5	97.5	97.5
16	NSC (MW)	981	981	981	981	981	981
17	ANOHR Equation	-35.11 x NOF + 13876					

	St. Lucie 1	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	87.4	87.4	87.4	87.4	87.4	87.4	87.4
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	12.6	12.6	12.6	12.6	12.6	12.6	12.6
4	EUOR (%)	12.6	12.6	12.6	12.6	12.6	12.6	12.6
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	744	720	744	8,784
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	70	70	68	70	68	70	826
11	MOH & EMOH	24	24	23	24	23	24	281
12	Oper Mbtu	7,439,023	7,439,023	7,199,052	7,439,023	7,308,021	7,551,631	88,398,302
13	Net Gen (MWH)	711,664	711,664	688,707	711,664	704,591	728,079	8,482,708
14	ANOHR (Btu/KWH)	10,453	10,453	10,453	10,453	10,372	10,372	10,421
15	NOF (%)	97.5	97.5	97.5	97.5	99.8	99.8	98.4
16	NSC (MW)	981	981	981	981	981	981	981
17	ANOHR Equation	-35.11 x NOF + 13876						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	St. Lucie 2	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	93.0	51.4	45.0	93.0	93.0	93.0
2	EPOF (%)	0.0	44.8	51.6	0.0	0.0	0.0
3	EUOF (%)	7.0	3.8	3.4	7.0	7.0	7.0
4	EUOR (%)	7.0	7.0	7.0	7.0	7.0	7.0
5	PH	744	696	744	720	744	720
6	SH	744	384	360	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	312	384	0	0	0
9	POH	0	312	384	0	0	0
10	FOH & EFOH	26	13	13	25	26	25
11	MOH & EMOH	26	13	13	25	26	25
12	Oper Mbtu	6,379,296	3,292,539	3,086,757	6,060,271	6,262,283	6,060,271
13	Net Gen (MWH)	623,343	321,726	301,618	589,635	609,290	589,635
14	ANOHR (Btu/KWH)	10,234	10,234	10,234	10,278	10,278	10,278
15	NOF (%)	99.7	99.7	99.7	97.5	97.5	97.5
16	NSC (MW)	840	840	840	840	840	840
17	ANOHR Equation	-20.11 x NOF + 12239					

	St. Lucie 2	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	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 (%)	7.0	7.0	7.0	7.0	7.0	7.0	6.9
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	744	720	744	8,088
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	281
11	MOH & EMOH	26	26	25	26	25	26	281
12	Oper Mbtu	6,262,283	6,262,283	6,060,271	6,262,283	6,173,504	6,379,296	68,543,293
13	Net Gen (MWH)	609,290	609,290	589,635	609,290	603,235	623,343	6,679,331
14	ANOHR (Btu/KWH)	10,278	10,278	10,278	10,278	10,234	10,234	10,262
15	NOF (%)	97.5	97.5	97.5	97.5	99.7	99.7	98.3
16	NSC (MW)	840	840	840	840	840	840	840
17	ANOHR Equation	-20.11 x NOF + 12239						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	Turkey Point 3	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	93.0	93.0	87.0	9.3	93.0	93.0
2	EPOF (%)	0.0	0.0	6.5	90.0	0.0	0.0
3	EUOF (%)	7.0	7.0	6.5	0.7	7.0	7.0
4	EUOR (%)	7.0	7.0	7.0	7.0	7.0	7.0
5	PH	744	696	744	720	744	720
6	SH	744	696	696	72	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	48	648	0	0
9	POH	0	0	48	648	0	0
10	FOH & EFOH	26	24	24	3	26	25
11	MOH & EMOH	26	24	24	3	26	25
12	Oper Mbtu	6,885,465	6,441,233	6,441,233	667,362	6,896,123	6,673,665
13	Net Gen (MWH)	623,119	582,917	582,917	58,757	607,160	587,574
14	ANOHR (Btu/KWH)	11,050	11,050	11,050	11,358	11,358	11,358
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	-118.45 x NOF + 22907					

	Turkey Point 3	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	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 (%)	7.0	7.0	7.0	7.0	7.0	7.0	6.9
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	744	720	744	8,088
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	281
11	MOH & EMOH	26	26	25	26	25	26	281
12	Oper Mbtu	6,896,123	6,896,123	6,673,665	6,896,123	6,663,349	6,885,465	74,976,486
13	Net Gen (MWH)	607,160	607,160	587,574	607,160	603,018	623,119	6,677,635
14	ANOHR (Btu/KWH)	11,358	11,358	11,358	11,358	11,050	11,050	11,228
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	-118.45 x NOF + 22907						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	Turkey Point 4	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	92.8	92.8	92.8	92.8	92.8	92.8
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	7.2	7.2	7.2	7.2	7.2	7.2
4	EUOR (%)	7.2	7.2	7.2	7.2	7.2	7.2
5	PH	744	696	744	720	744	720
6	SH	744	696	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	27	25	27	26	27	26
11	MOH & EMOH	27	25	27	26	27	26
12	Oper Mbtu	6,657,034	6,227,552	6,657,034	6,290,197	6,499,865	6,290,197
13	Net Gen (MWH)	615,139	575,453	615,139	576,342	595,553	576,342
14	ANOHR (Btu/KWH)	10,822	10,822	10,822	10,914	10,914	10,914
15	NOF (%)	100.7	100.7	100.7	97.5	97.5	97.5
16	NSC (MW)	821	821	821	821	821	821
17	ANOHR Equation	-28.86 x NOF + 13728					

	Turkey Point 4	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	92.8	92.8	92.8	12.0	52.6	92.8	82.7
2	EPOF (%)	0.0	0.0	0.0	87.1	43.3	0.0	10.9
3	EUOF (%)	7.2	7.2	7.2	0.9	4.1	7.2	6.4
4	EUOR (%)	7.2	7.2	7.2	7.2	7.2	7.2	7.2
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	96	408	744	7,824
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	648	312	0	960
9	POH	0	0	0	648	312	0	960
10	FOH & EFOH	27	27	26	3	15	27	281
11	MOH & EMOH	27	27	26	3	15	27	281
12	Oper Mbtu	6,499,865	6,499,865	6,290,197	838,697	3,712,903	6,770,594	69,244,807
13	Net Gen (MWH)	595,553	595,553	576,342	76,846	345,290	629,647	6,373,199
14	ANOHR (Btu/KWH)	10,914	10,914	10,914	10,914	10,753	10,753	10,865
15	NOF (%)	97.5	97.5	97.5	97.5	103.1	103.1	99.2
16	NSC (MW)	821	821	821	821	821	821	821
17	ANOHR Equation	-28.86 x NOF + 13728						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	West County 1	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	90.2	90.2	78.6	82.2	70.8	90.2
2	EPOF (%)	0.0	0.0	12.9	8.9	21.5	0.0
3	EUOF (%)	9.8	9.8	8.5	8.9	7.7	9.8
4	EUOR (%)	9.8	9.8	8.5	8.9	7.7	9.8
5	PH	744	696	744	720	744	720
6	SH	744	696	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	20	18	17	17	15	19
11	MOH & EMOH	53	50	46	47	42	51
12	Oper Mbtu	4,624,696	4,383,484	5,178,472	5,103,205	4,682,165	5,845,263
13	Net Gen (MWH)	647,898	614,622	731,216	721,607	656,501	835,993
14	ANOHR (Btu/KWH)	7,138	7,132	7,082	7,072	7,132	6,992
15	NOF (%)	68.9	69.9	77.8	79.3	69.8	91.9
16	NSC (MW)	1,264	1,264	1,264	1,264	1,264	1,264
17	ANOHR Equation	-6.34 x NOF + 7575					

	West County 1	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	90.2	90.2	90.2	17.5	0.0	32.0	68.5
2	EPOF (%)	0.0	0.0	0.0	80.6	100.0	64.5	24.1
3	EUOF (%)	9.8	9.8	9.8	1.9	0.0	3.5	7.4
4	EUOR (%)	9.8	9.8	9.8	9.8	0.0	10.4	9.3
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	144	0	247	6,967
7	RSH	0	0	0	0	0	17	17
8	UH	0	0	0	600	720	480	1,800
9	POH	0	0	0	600	720	480	1,800
10	FOH & EFOH	20	20	19	4	0	7	176
11	MOH & EMOH	53	53	51	10	0	19	474
12	Oper Mbtu	6,022,275	6,040,267	5,863,464	1,061,154	0	1,651,859	50,510,255
13	Net Gen (MWH)	860,940	863,759	838,836	150,497	0	232,558	7,154,427
14	ANOHR (Btu/KWH)	6,995	6,993	6,990	7,051	0	7,103	7,060
15	NOF (%)	91.5	91.8	92.2	82.7	0.0	74.5	81.2
16	NSC (MW)	1,264	1,264	1,264	1,264	1,264	1,264	1,264
17	ANOHR Equation	-6.34 x NOF + 7575						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

	West County 2	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	92.9	92.9	92.9	59.8	92.9	92.9
2	EPOF (%)	0.0	0.0	0.0	35.6	0.0	0.0
3	EUOF (%)	7.1	7.1	7.1	4.6	7.1	7.1
4	EUOR (%)	7.1	7.1	7.1	6.2	7.1	7.1
5	PH	744	696	744	720	744	720
6	SH	744	696	744	528	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	192	0	0
9	POH	0	0	0	192	0	0
10	FOH & EFOH	15	14	15	10	15	15
11	MOH & EMOH	38	35	38	23	38	36
12	Oper Mbtu	5,167,830	4,815,411	5,689,102	3,482,851	5,955,933	5,676,680
13	Net Gen (MWH)	742,291	691,472	824,388	498,262	866,948	824,979
14	ANOHR (Btu/KWH)	6,962	6,964	6,901	6,990	6,870	6,881
15	NOF (%)	78.9	78.6	87.7	74.7	92.2	90.6
16	NSC (MW)	1,264	1,264	1,264	1,264	1,264	1,264
17	ANOHR Equation	-6.85 x NOF + 7502					

	West County 2	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	92.9	92.9	92.9	92.9	92.9	92.9	90.2
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.9
3	EUOF (%)	7.1	7.1	7.1	7.1	7.1	7.1	6.9
4	EUOR (%)	7.1	7.1	7.1	7.1	7.1	7.1	7.1
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	720	744	720	744	8,592
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	192
9	POH	0	0	0	0	0	0	192
10	FOH & EFOH	15	15	15	15	15	15	176
11	MOH & EMOH	38	38	36	38	36	38	430
12	Oper Mbtu	5,729,834	5,722,753	5,722,015	5,609,659	5,241,403	5,201,916	64,035,367
13	Net Gen (MWH)	830,772	829,625	832,172	811,700	756,008	747,724	9,256,341
14	ANOHR (Btu/KWH)	6,897	6,898	6,876	6,911	6,933	6,957	6,918
15	NOF (%)	88.3	88.2	91.4	86.3	83.1	79.5	85.2
16	NSC (MW)	1,264	1,264	1,264	1,264	1,264	1,264	1,264
17	ANOHR Equation	-6.85 x NOF + 7502						

ESTIMATED UNIT PERFORMANCE DATA

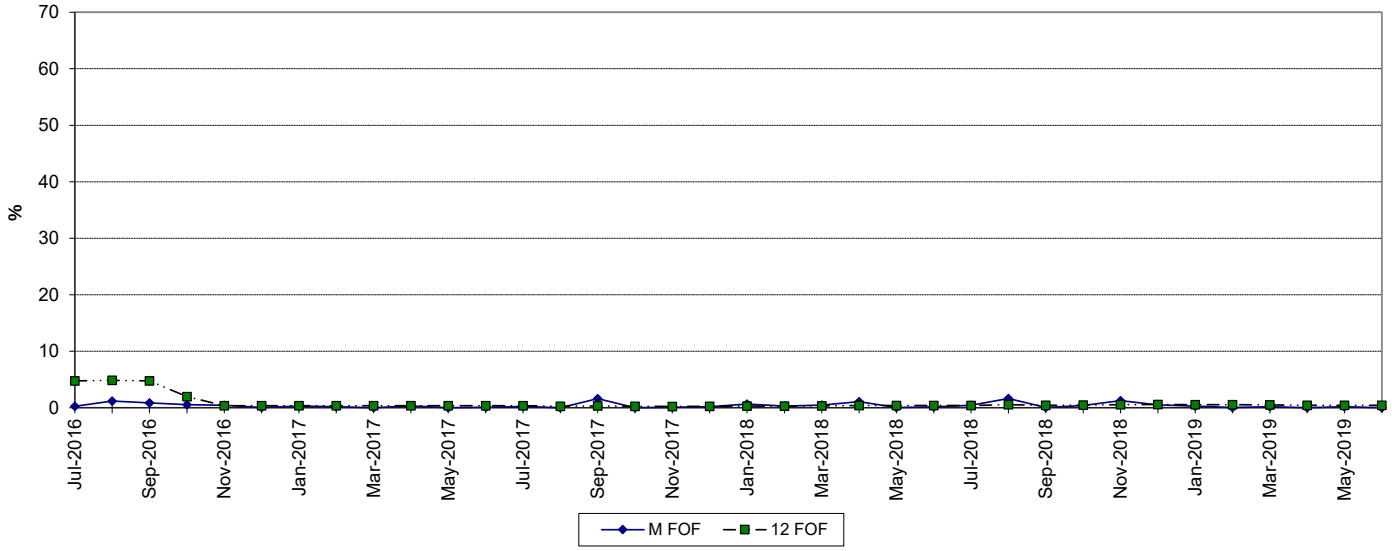
FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

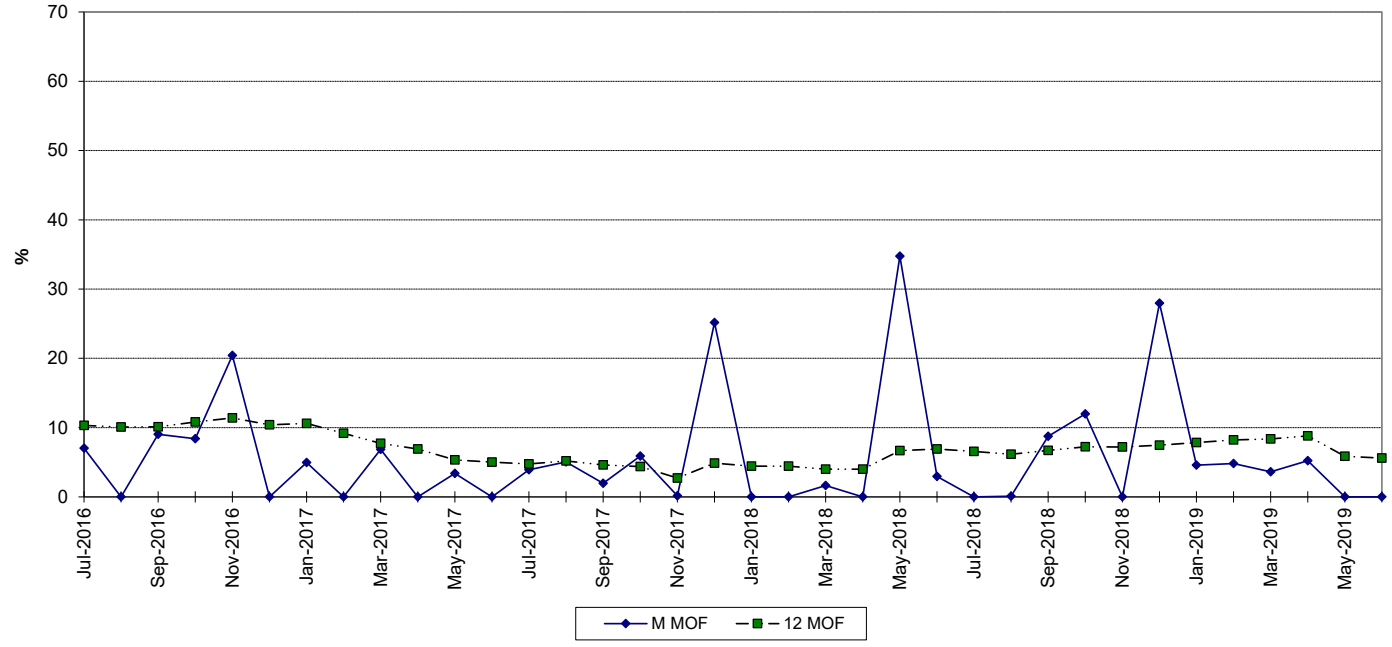
	West County 3	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20
1	EAF (%)	91.3	91.3	91.3	91.3	91.3	91.3
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	8.7	8.7	8.7	8.7	8.7	8.7
4	EUOR (%)	8.7	8.7	8.7	8.7	8.7	8.7
5	PH	744	696	744	720	744	720
6	SH	744	696	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	16	15	16	15	16	15
11	MOH & EMOH	49	45	49	47	49	47
12	Oper Mbtu	4,535,896	4,443,934	5,318,718	5,532,973	5,786,954	5,579,960
13	Net Gen (MWH)	647,800	636,758	768,712	804,562	842,474	812,103
14	ANOHR (Btu/KWH)	7,002	6,979	6,919	6,877	6,869	6,871
15	NOF (%)	69.8	73.4	82.9	89.6	90.8	90.5
16	NSC (MW)	1,247	1,247	1,247	1,247	1,247	1,247
17	ANOHR Equation	-6.31 x NOF + 7442					

	West County 3	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1	EAF (%)	91.3	91.3	25.4	84.5	91.3	91.3	85.3
2	EPOF (%)	0.0	0.0	72.2	7.5	0.0	0.0	6.6
3	EUOF (%)	8.7	8.7	2.4	8.0	8.7	8.7	8.1
4	EUOR (%)	8.7	8.7	6.0	8.0	8.7	8.7	8.5
5	PH	744	744	720	744	720	744	8,784
6	SH	744	744	288	744	720	744	8,352
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	432	0	0	0	432
9	POH	0	0	432	0	0	0	432
10	FOH & EFOH	16	16	4	15	15	16	176
11	MOH & EMOH	49	49	13	45	47	49	536
12	Oper Mbtu	5,753,333	5,760,282	1,599,705	5,246,413	5,052,282	4,893,686	59,548,305
13	Net Gen (MWH)	837,092	838,225	227,134	757,386	729,045	702,712	8,604,003
14	ANOHR (Btu/KWH)	6,873	6,872	7,043	6,927	6,930	6,964	6,921
15	NOF (%)	90.2	90.3	63.2	81.6	81.2	75.7	82.6
16	NSC (MW)	1,247	1,247	1,247	1,247	1,247	1,247	1,247
17	ANOHR Equation	-6.31 x NOF + 7442						

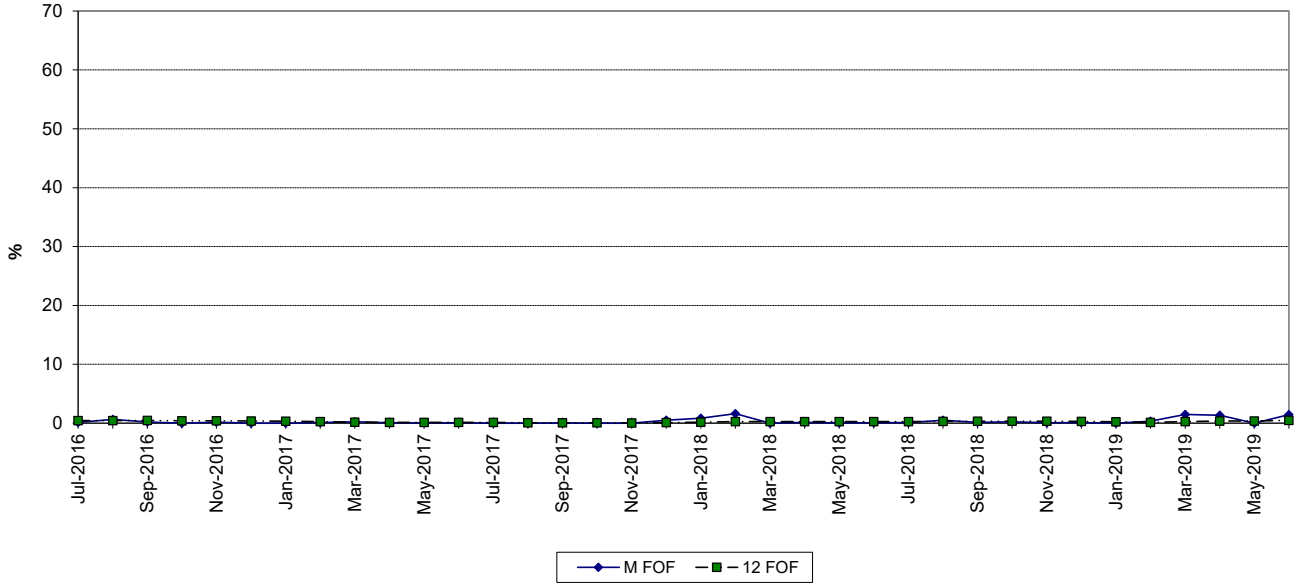
CAPE CANAVERAL 3
FORCED OUTAGE FACTOR



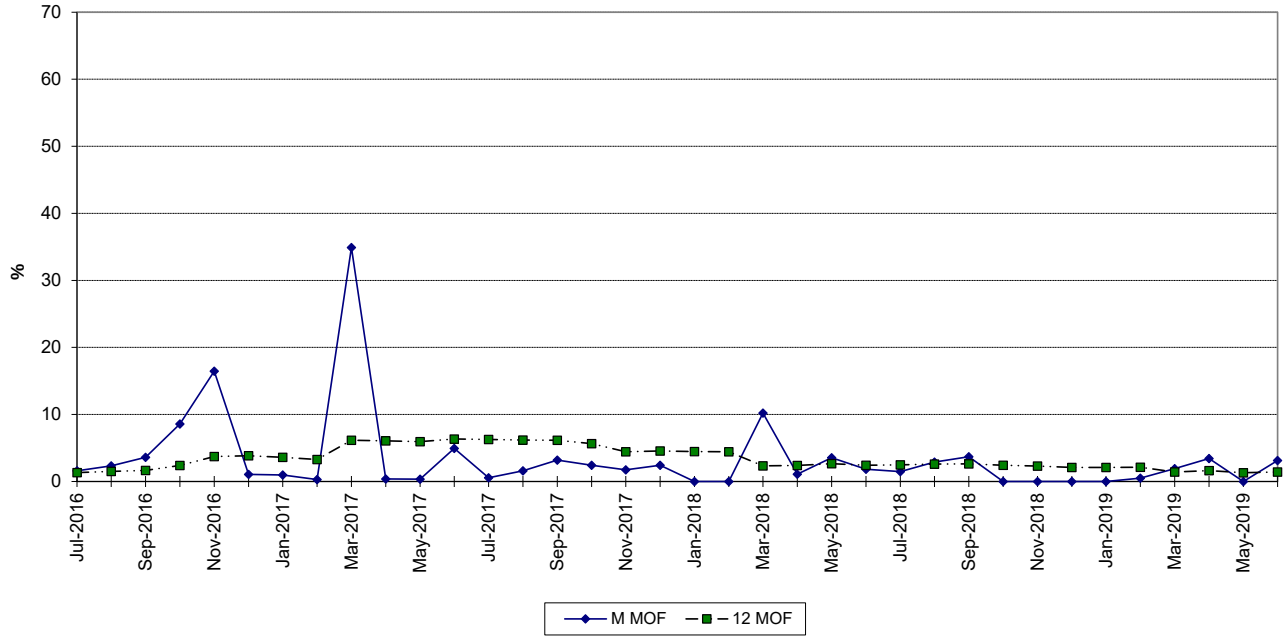
MAINTENANCE OUTAGE FACTOR



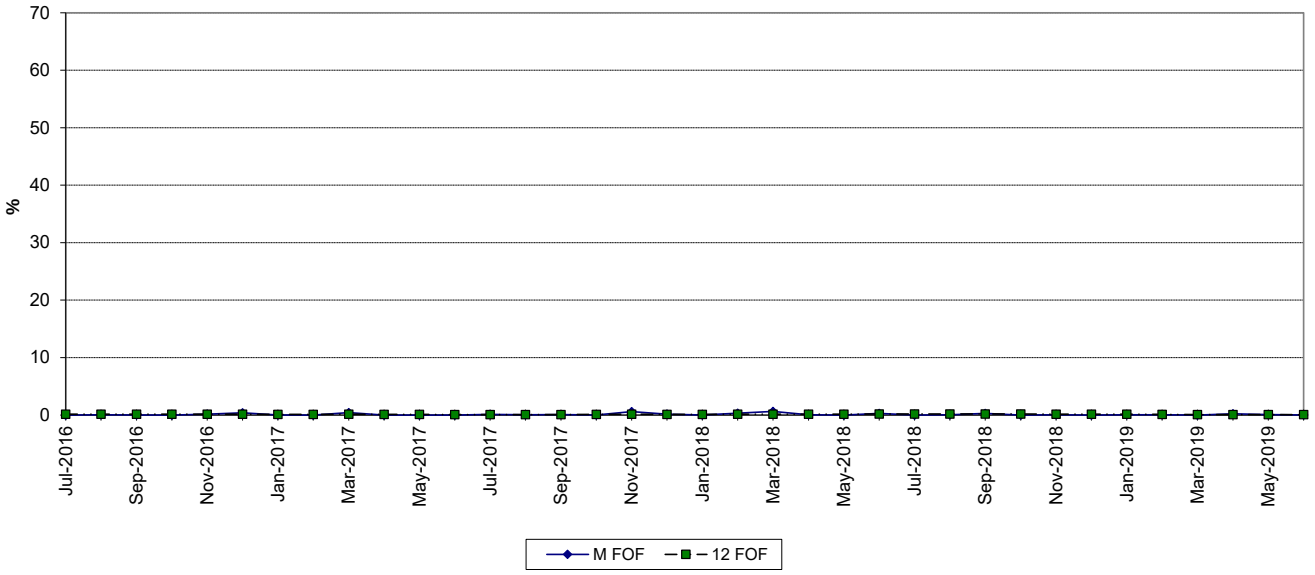
FT. MYERS 2
FORCED OUTAGE FACTOR



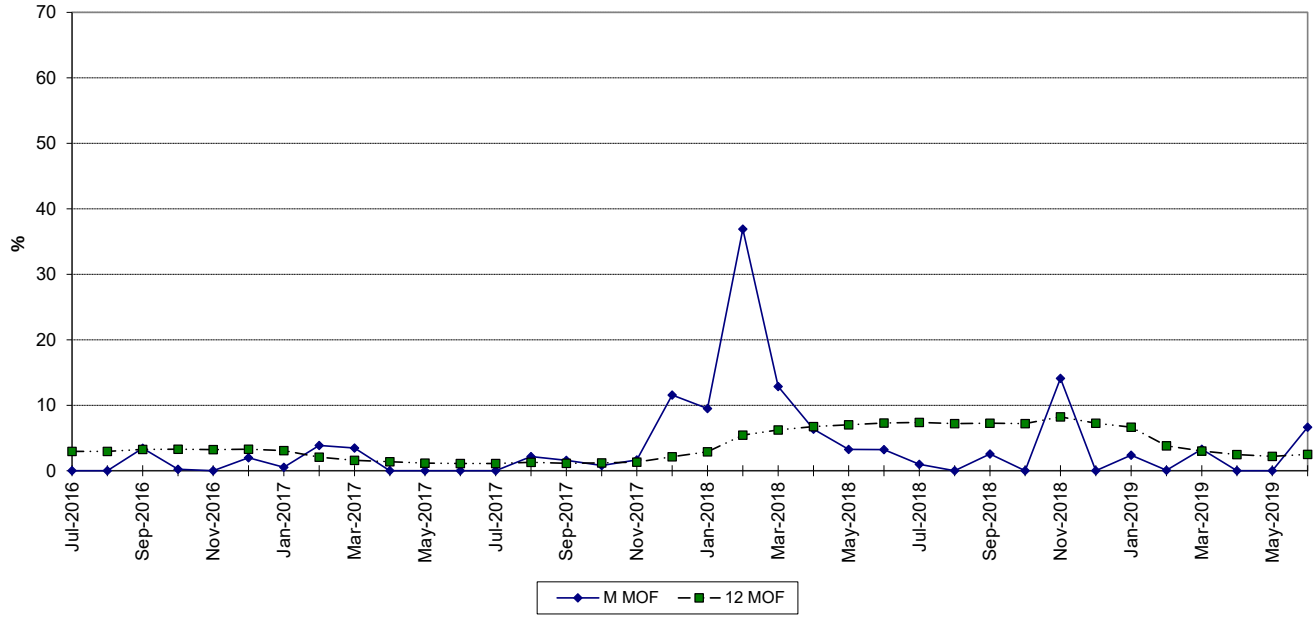
MAINTENANCE OUTAGE FACTOR



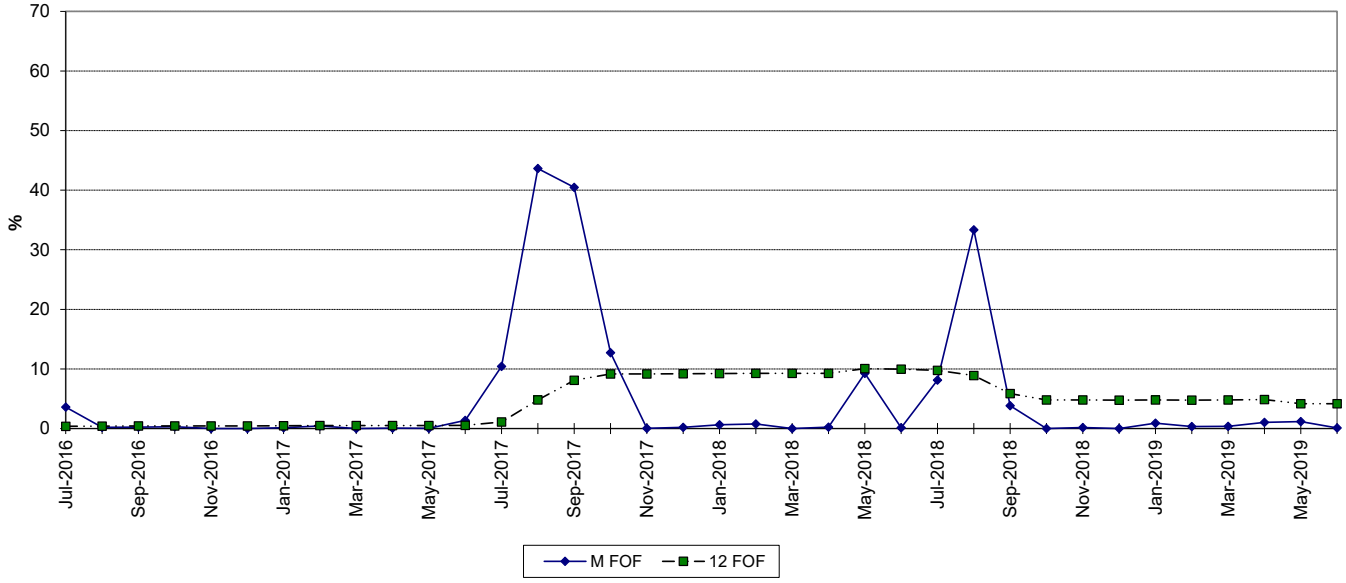
MANATEE 3
FORCED OUTAGE FACTOR



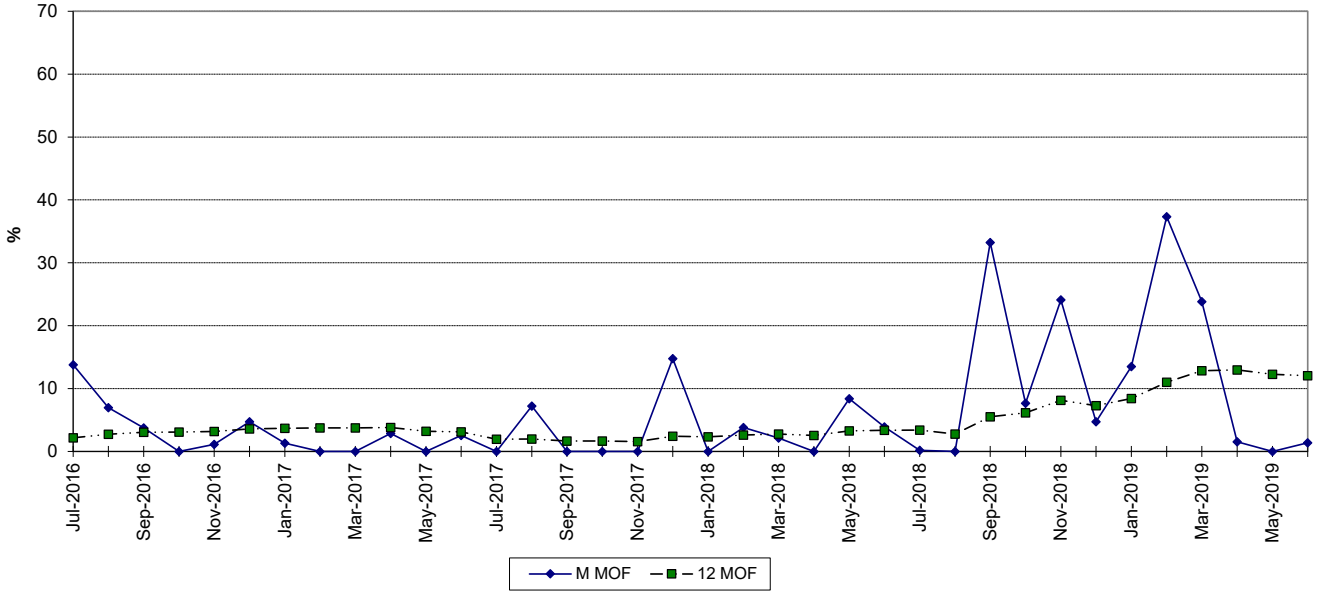
MAINTENANCE OUTAGE FACTOR



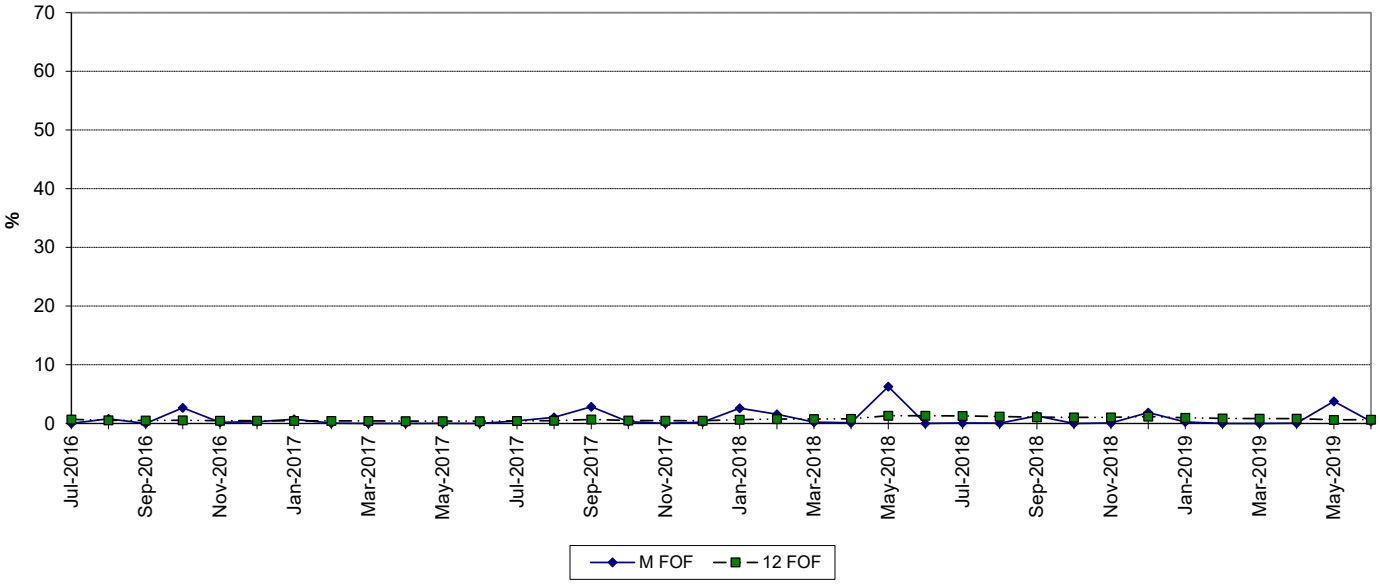
PORT EVERGLADES 5
FORCED OUTAGE FACTOR



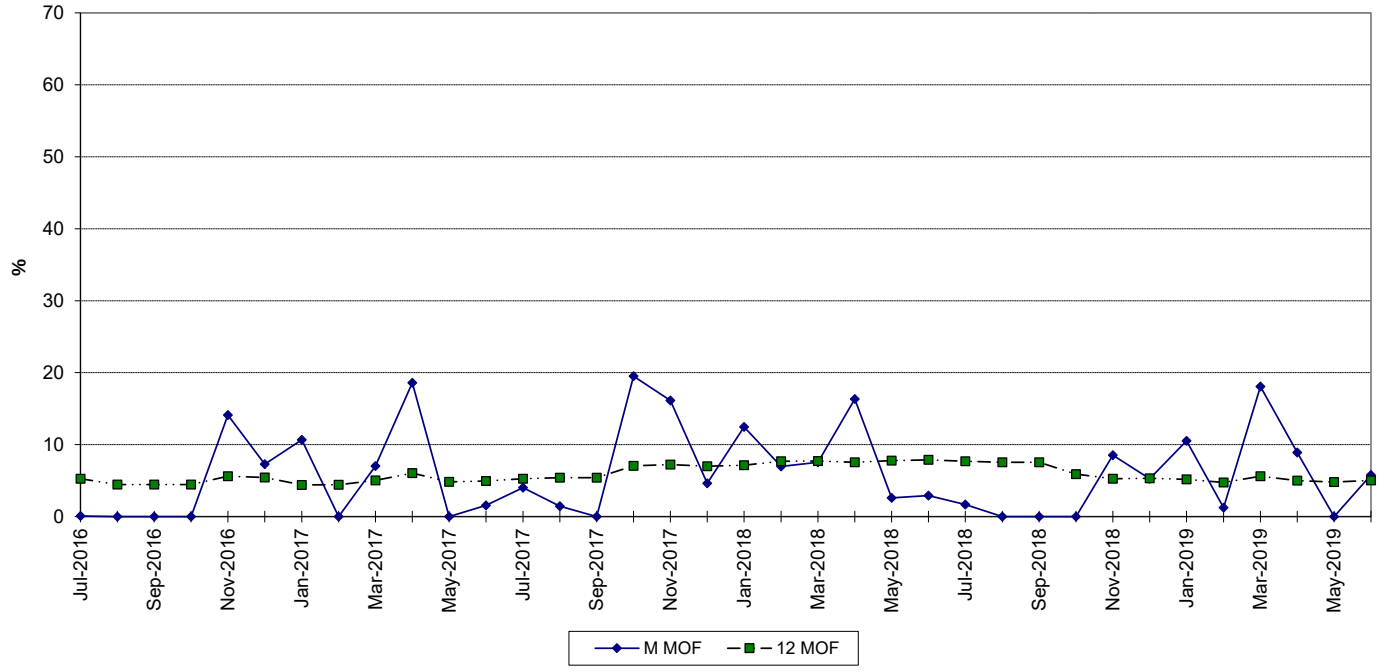
MAINTENANCE OUTAGE FACTOR



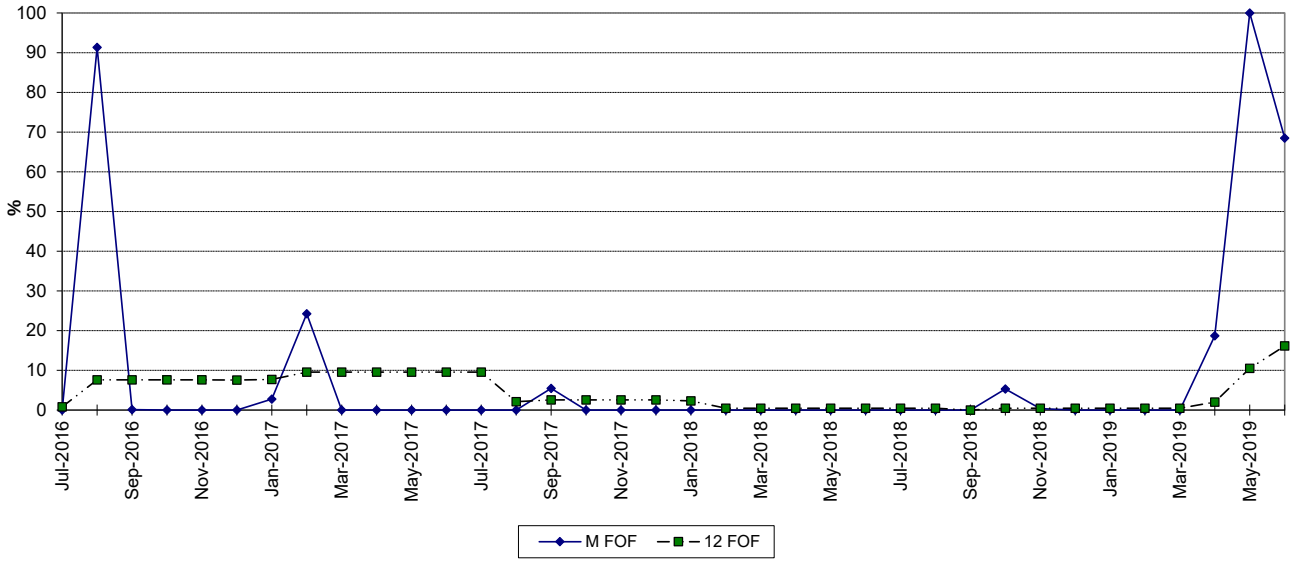
RIVIERA 5
FORCED OUTAGE FACTOR



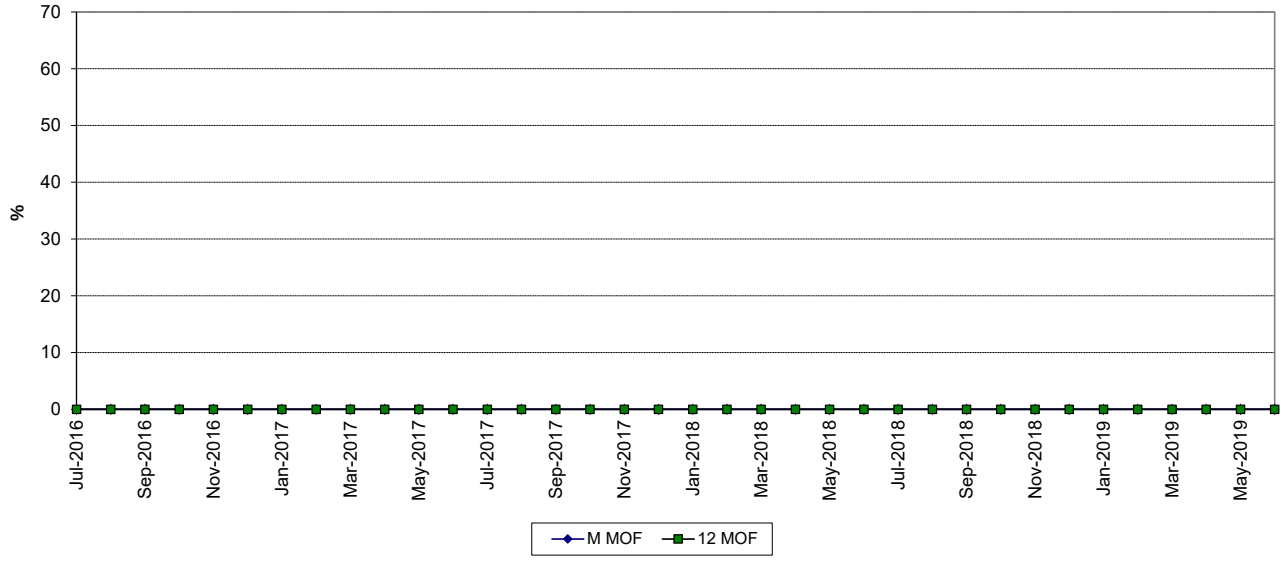
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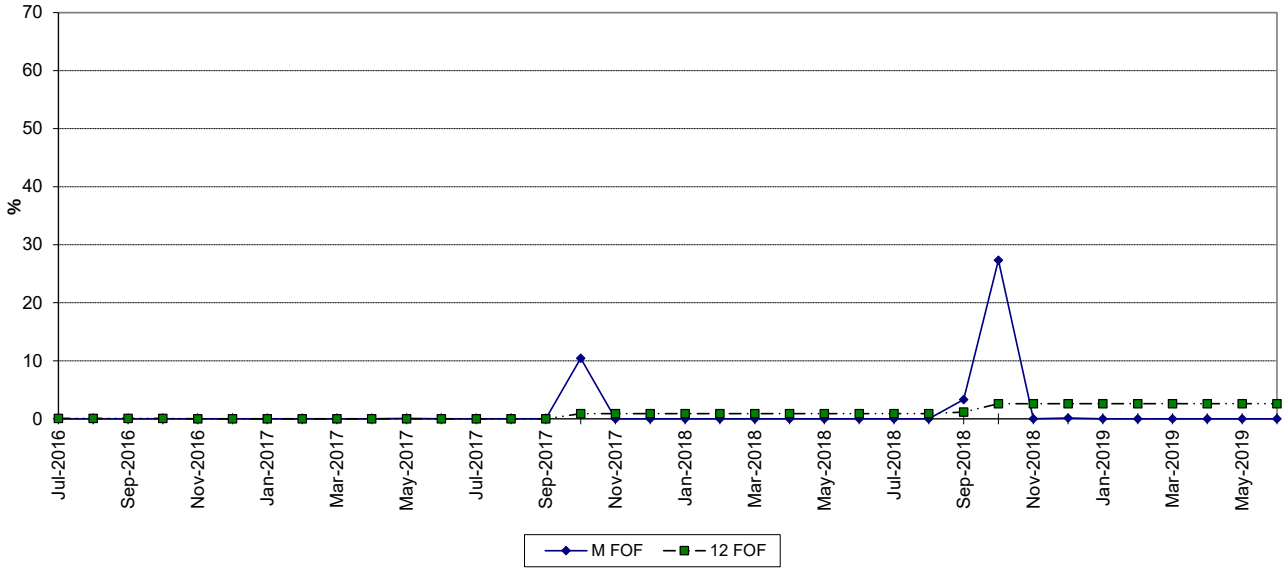
ST. LUCIE 1
FORCED OUTAGE FACTOR



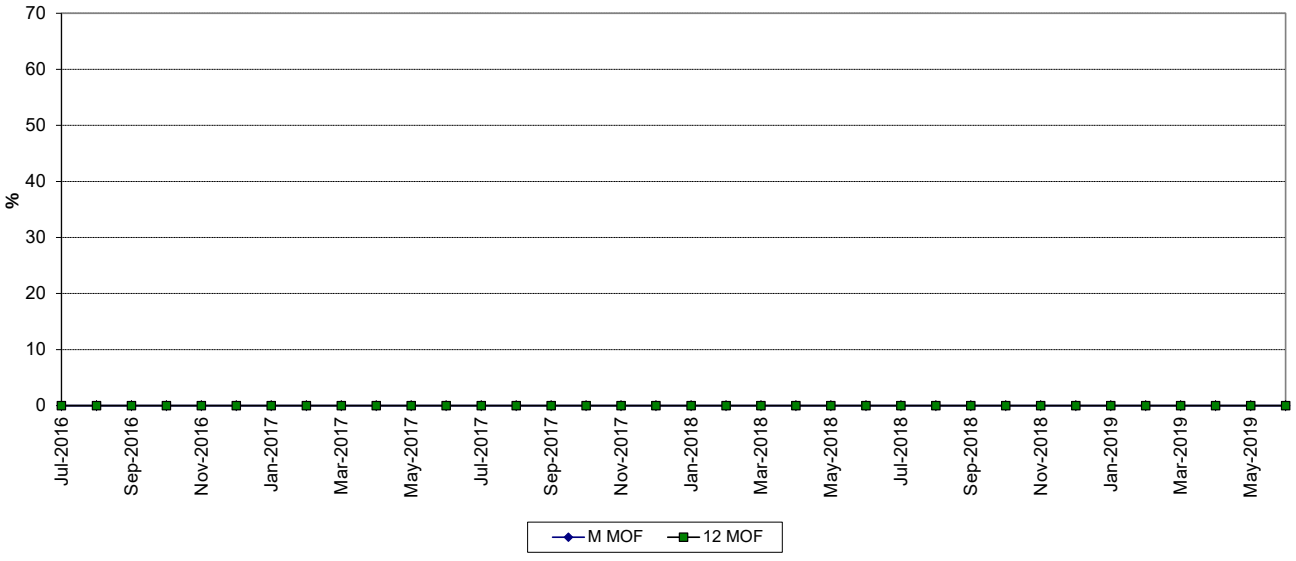
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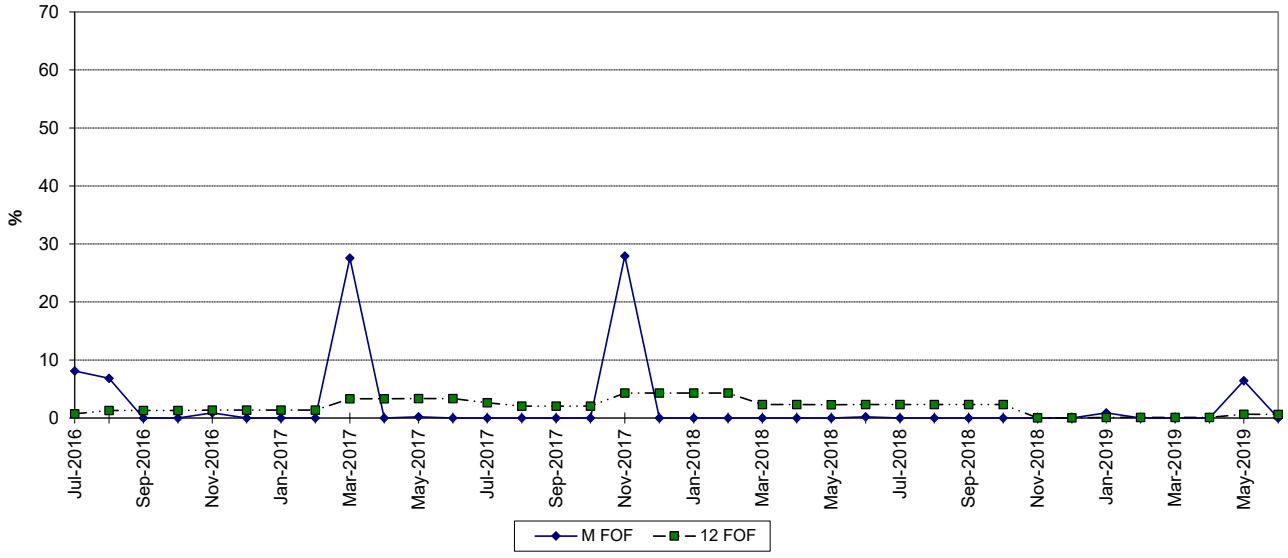
ST. LUCIE 2
FORCED OUTAGE FACTOR



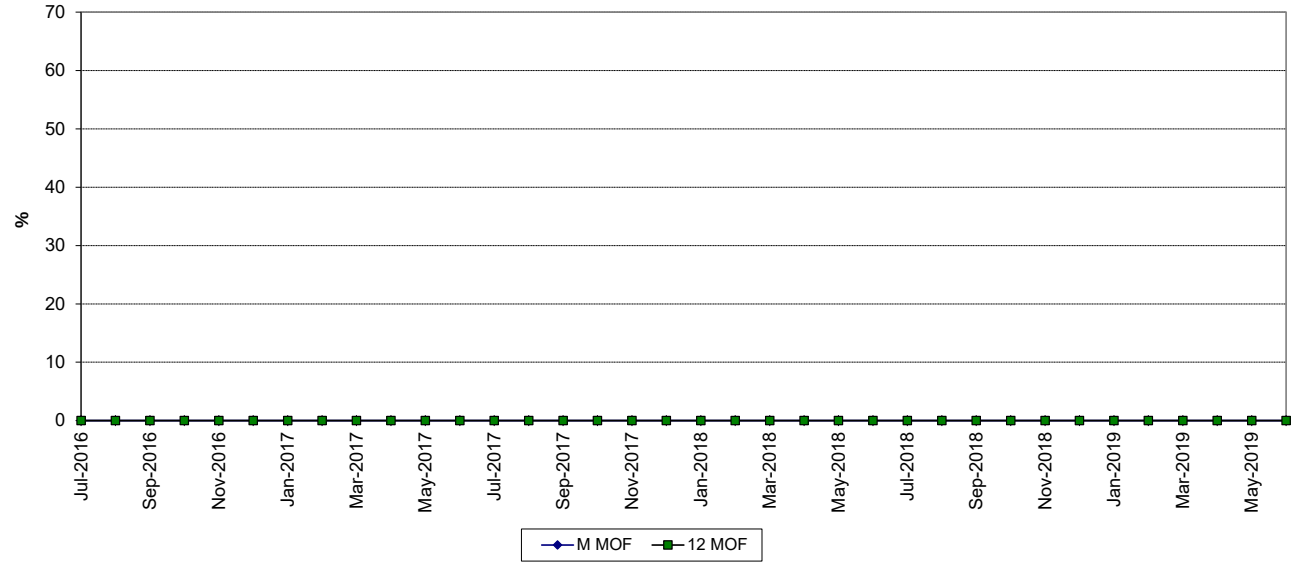
MAINTENANCE OUTAGE FACTOR



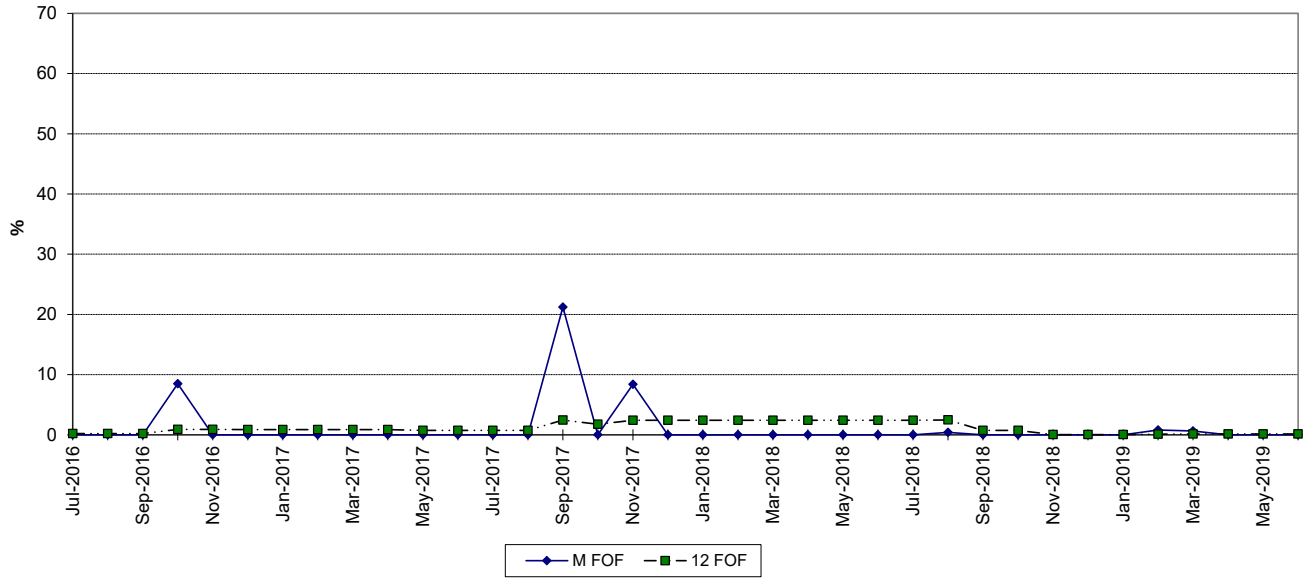
TURKEY POINT 3
FORCED OUTAGE FACTOR



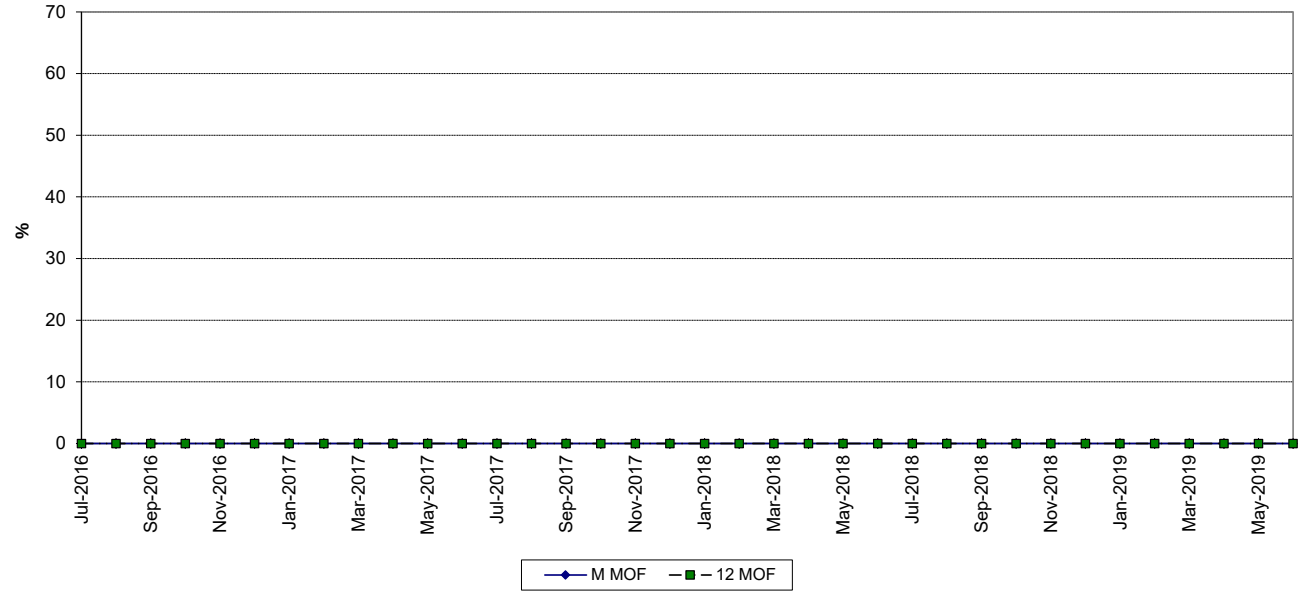
MAINTENANCE OUTAGE FACTOR



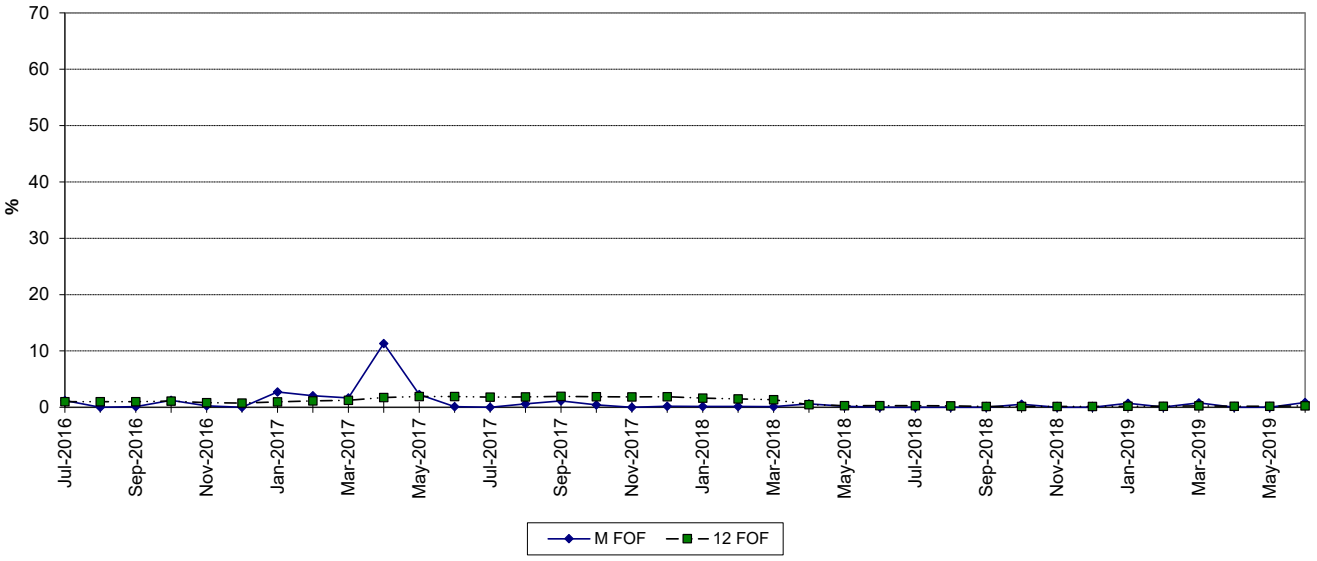
TURKEY POINT 4
FORCED OUTAGE FACTOR



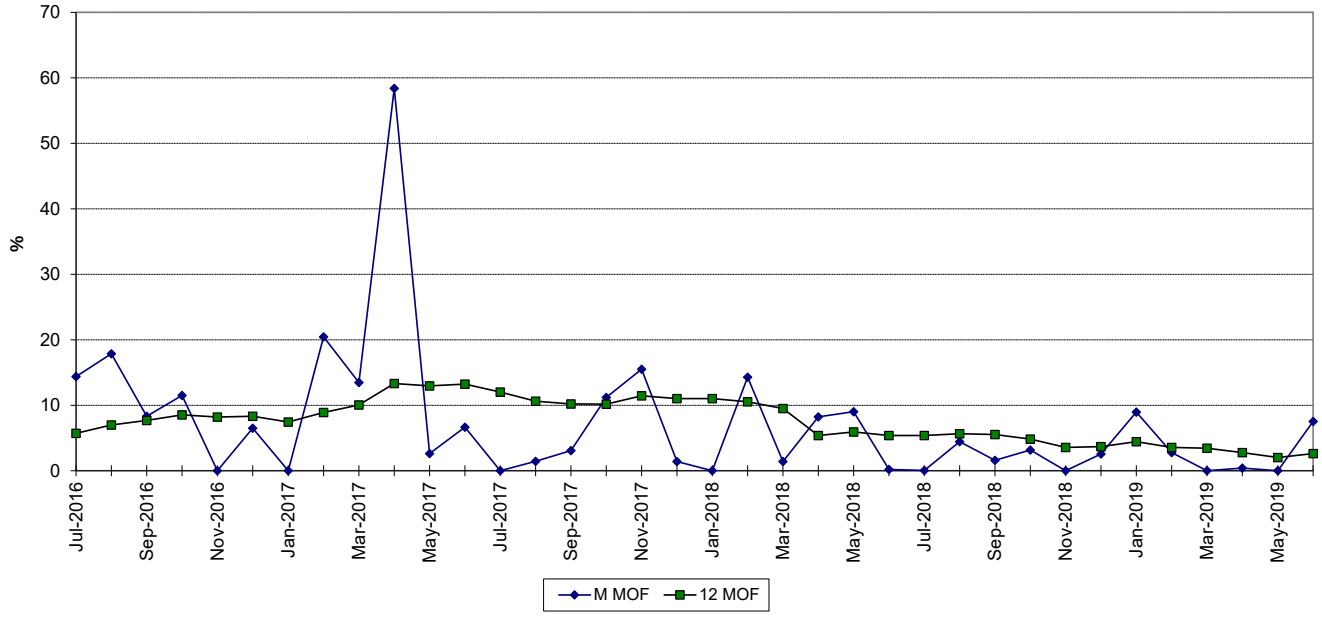
MAINTENANCE OUTAGE FACTOR



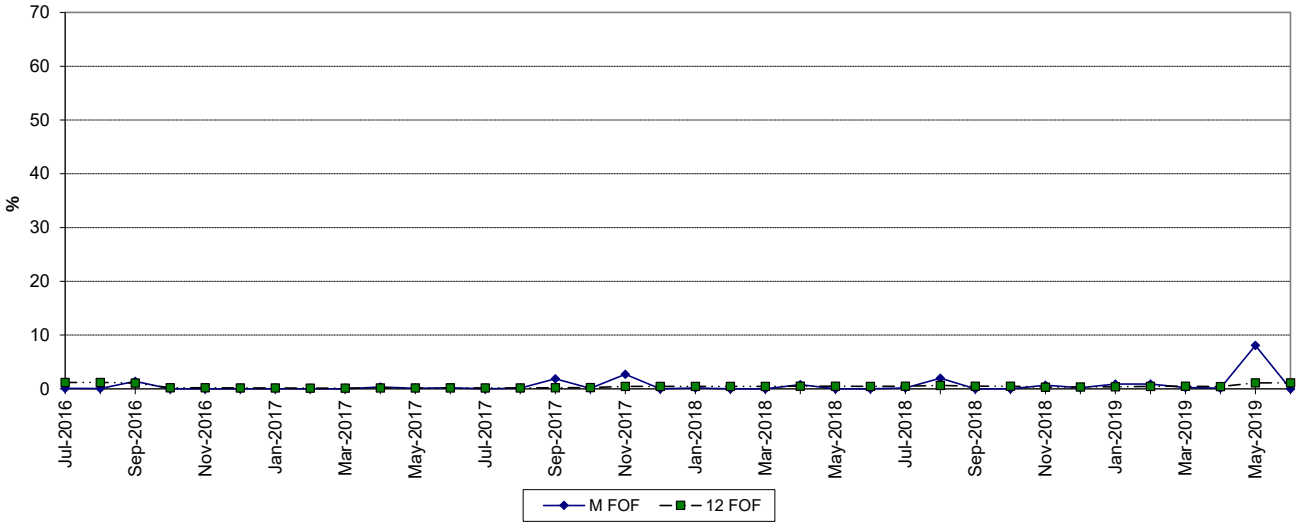
WEST COUNTY 1
FORCED OUTAGE FACTOR



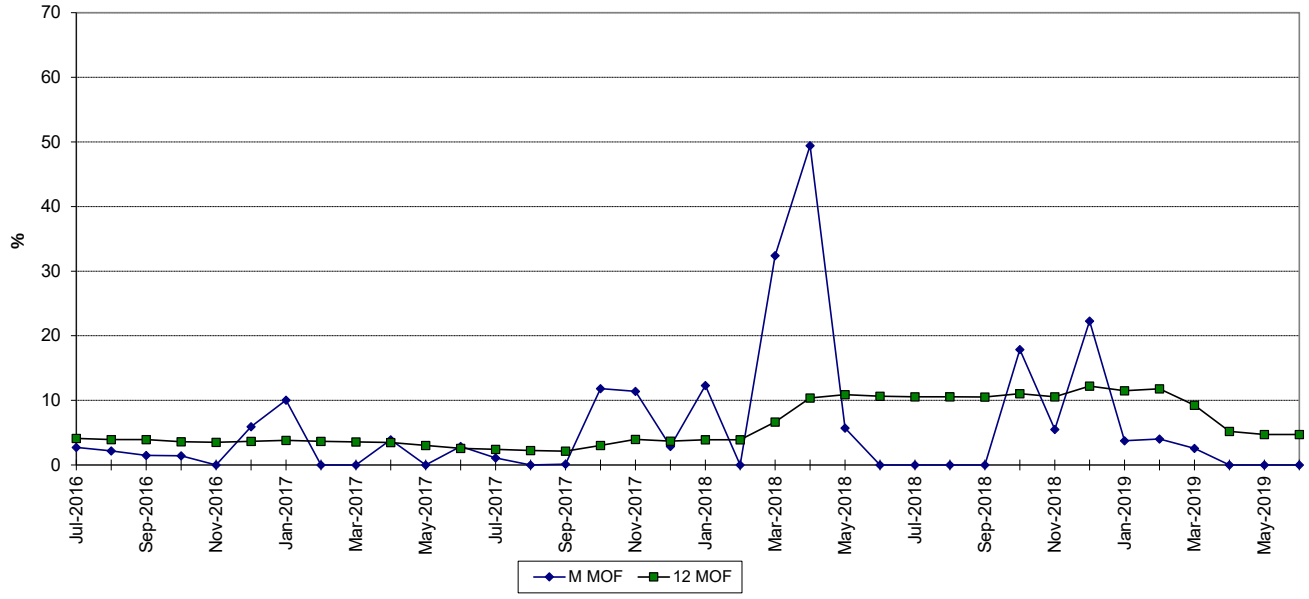
MAINTENANCE OUTAGE FACTOR



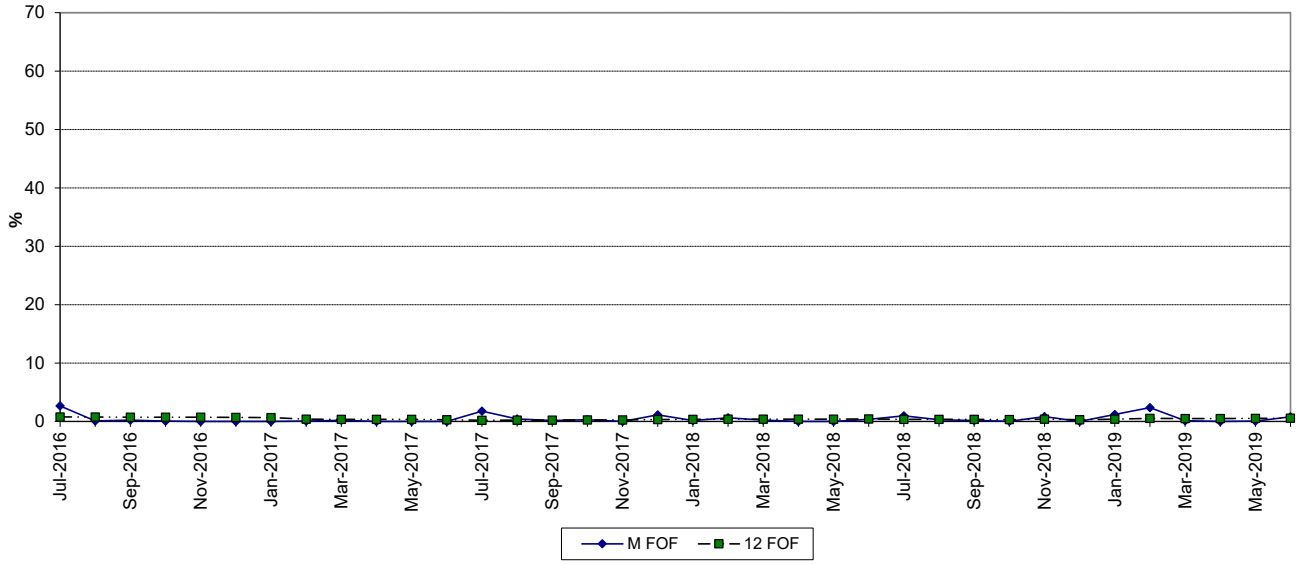
WEST COUNTY 2
FORCED OUTAGE FACTOR



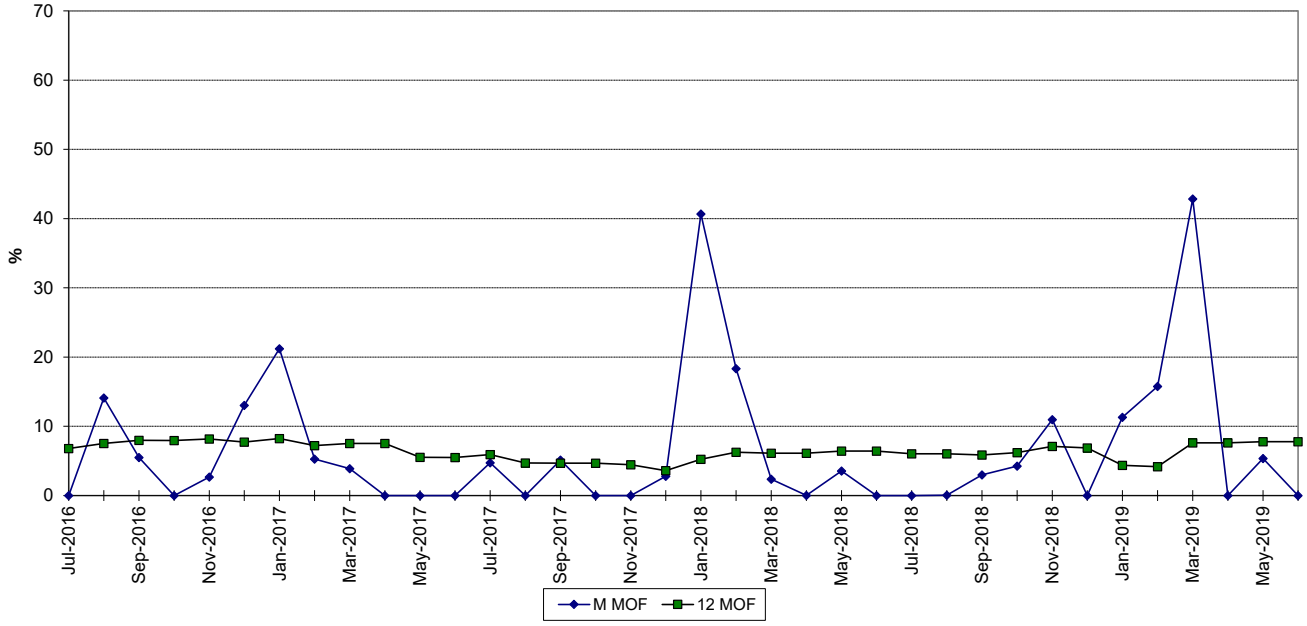
MAINTENANCE OUTAGE FACTOR



WEST COUNTY 3
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2020

PLANT/UNIT	PLAN OUTAGE	REASON FOR OUTAGE	LR MW*
Cape Canaveral 3	02/12/2020 - 03/26/2020	PCC31 CT-CI-MAJOR-RELIABILITY	436
Cape Canaveral 3	02/29/2020 - 03/27/2020	PCC3 STM TURB-VALVES-GENERATOR MINOR- DCS MINOR	1,307
Ft. Myers 2	02/15/2020 - 02/21/2020	ST MAINT-OH, Cyber Vulnerability Assessment (CVA) & PFM2A MAINT-ANNUAL-RELIABILITY	1,791
Ft. Myers 2	02/22/2020 - 02/28/2020	PFM2C & PFM2F MAINTENANCE-ANNUAL-RELIABILITY	597
Ft. Myers 2	09/01/2020 - 09/14/2020	PFM2B GEN-MINOR	296
Ft. Myers 2	09/15/2020 - 09/28/2020	PFM2D GEN-MINOR	296
Ft. Myers 2	11/01/2020 - 11/14/2020	PFM2E-GEN-MINOR	299
Manatee 3	11/12/2020 - 11/18/2020	PMT3A & PMT3B MAINTENANCE-ANNUAL-RELIABILITY	626
Manatee 3	11/19/2020 - 11/25/2020	PMT3, PMT3C & PMT3D MAINTENANCE-ANNUAL-RELIABILITY	1,251
Port Everglades 5	04/05/2020 - 05/02/2020	PPE53-CT-CI	421
Port Everglades 5	05/05/2020 - 06/14/2020	PPE51 CT-HGP-ROTOR SWAP	421
Port Everglades 5	05/17/2020 - 05/28/2020	PPE5 MAINT-NERC CIP & CVA & PPE52 MAINT-ANNUAL- RELIABILITY	1,264
Riviera 5	10/15/2020 - 11/11/2020	PRV5 STM TURB-VALVES-GEN MINOR & PRV51, 52 & 53 HRSG-MAJORS	1,309
St. Lucie 1	NONE		
St. Lucie 2	02/17/2020 - 03/17/2020	REFUELING	860
Turkey Point 3	03/30/2020 - 04/28/2020	REFUELING	837
Turkey Point 4	10/05/2020 - 11/14/2020	REFUELING	821
West County 1	03/20/2020 - 04/08/2020	PWC1A-HRSG-MAJOR-CT OUTLET DUCT	422
West County 1	05/01/2020 - 05/20/2020	PWC1C-HRSG-MAJOR-CT OUTLET DUCT	421
West County 1	10/07/2020 - 12/20/2020	PWC1 ST TURB-HP IP-GEN MAJOR, BOP & PWC1A, 1B & 1C MAINT-ANNUAL-RELIABILIT'	1,264
West County 2	04/09/2020 - 04/18/2020	PWC2A MAINTENANCE-ANNUAL-RELIABILITY	421
West County 2	04/11/2020 - 04/15/2020	PWC2 MAINTENANCE-ANNUAL-BOP-RELIABILITY	1,264
West County 2	04/11/2020 - 04/20/2020	PWC2B MAINTENANCE-ANNUAL-RELIABILITY	421
West County 2	04/13/2020 - 04/22/2020	PWC2C MAINTENANCE-ANNUAL-RELIABILITY	421
West County 3	09/06/2020 - 09/29/2020	PWC3A MAINTENANCE-ANNUAL-RELIABILITY.	416
West County 3	09/09/2020 - 10/02/2020	PWC3B MAINTENANCE-ANNUAL-RELIABILITY.	416
West County 3	09/12/2020 - 09/29/2020	PWC3 MAINTENANCE-ANNUAL-ST RELIABILITY.	1,247
West County 3	09/12/2020 - 10/05/2020	PWC3C MAINTENANCE-ANNUAL-RELIABILITY.	416

*Approximate load reduction MW are based on the unit's estimated MW rating at the start of the outage period

FLORIDA POWER & LIGHT COMPANY
2020 SoBRA
FIRST YEAR ANNUALIZED REVENUE REQUIREMENT[1]

Line No	(1) Description	(2) Page Reference	(3) Amount ($000's)
1	Jurisdictional Adjusted Rate Base	Page 2	$ 363,770
2	Rate of Return on Rate Base	Page 3	8.26%
3	Required Jurisdictional Net Operating Income	Line 1 x Line 2	$ 30,065
4	Required Net Operating Income	Page 4	(7,577)
5	Net Operating Income Deficiency (Excess)	Line 3 - Line 4	$ 37,642
6	Net Operating Income Multiplier[2]		1.34135
7	Revenue Requirement	Line 5 x Line 6	$ 50,491
8			

9 NOTES:

10 [1] Represents the revenue requirement for projected 12-month period for the 2020 Project.

11 [2] Represents the net operating income multiplier from page 9 of Exhibit KO-20, Docket No. 160021-EI, revised to incorporate the 21% corporate federal income tax rate per the Tax Cuts and Jobs Act of 2017.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 28
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: L. Fuentes LF-1

FLORIDA POWER & LIGHT COMPANY
2020 SoBRA
JURISDICTIONAL ADJUSTED RATE BASE
13-MONTH AVERAGE

Line No.	(1) Description	(2) Total Company ($000)	(3) FPSC Jurisdictional ($000)	(4) Jurisdictional Factor[1]
1				
2	PLANT IN SERVICE:			
3				
4	ELECTRIC PLANT IN SERVICE - OTHER PRODUCTION	$ 360,783	$ 340,443	0.943622
5				
6	ELECTRIC PLANT IN SERVICE - TRANSMISSION	$ 27,217	$ 24,626	0.904796
7	ELECTRIC PLANT IN SERVICE - TRANSMISSION - GSU	4,328	4,110	0.949591
8	TOTAL ELECTRIC PLANT IN SERVICE - TRANSMISSION	$ 31,545	$ 28,736	0.910942
9				
10	NON-DEPRECIABLE PROPERTY (LAND) [2]	$ 18,371	$ 17,335	0.943622
11				
12	TOTAL PLANT IN SERVICE	$ 410,699	$ 386,513	0.941112
13				
14				
15	ACCUMULATED PROVISION FOR DEPRECIATION:			
16				
17	ACCUM PROVISION FOR DEPRECIATION - OTHER PRODUCTION	$ (6,079)	$ (5,736)	0.943622
18				
19	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION	$ (272)	$ (246)	0.904796
20	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION - GSU	(57)	(54)	0.949591
21	TOTAL ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION	$ (329)	$ (301)	0.912568
22				
23	TOTAL ACCUMULATED PROVISION FOR DEPRECIATION	$ (6,408)	$ (6,037)	0.942026
24				
25				
26	ACCUMULATED DEFERRED INCOME TAXES[3]	$ (17,752)	$ (16,707)	0.941126
27				
28	TOTAL RATE BASE	$ 386,538	$ 363,770	0.941096
29				
30				
31	NOTES:			
32	[1] Based on FPL's most recent cost of service calculations.			
33	[2] Does not include land for the Okeechobee Solar Energy Center.			
34	[3] Detailed calculation for accumulated deferred income taxes is provided on Page 5.			

FLORIDA POWER & LIGHT COMPANY
2020 SoBRA
RATE OF RETURN ON RATE BASE
13-MONTH AVERAGE

Line No.	Class of Capital	(1) Company Total Per Books ($000)	(2) Jurisdictional Factor	(3) Jurisdictional Capital Structure ($000)	(4) Ratio	(5) Cost Rate [1]	(6) Weighted Cost Rate
1	LONG TERM DEBT	$ 107,789	0.941096	$ 101,440	27.89%	4.44%	1.24%
2							
3	COMMON EQUITY	180,369	0.941096	169,744	46.66%	10.55%	4.92%
4							
5	INVESTMENT TAX CREDITS	98,381	0.941096	92,586	25.45%	8.26%	2.10%
6							
7	TOTAL	$ 386,538		$ 363,770	100.00%		8.26%
8							
9							
10	NOTE:						
11	[1] Represents the cost rates from Schedule 4, Page 1 of 2 of FPL's May 2019 Earnings Surveillance Report.						

FLORIDA POWER & LIGHT COMPANY
2020 SoBRA
REQUIRED NET OPERATING INCOME

Line No.	Account No.	(1) Account Title	(2) Total Company ($000)	(3) FPSC Jurisdictional ($000)	(4) Jurisdictional Separation Factor[1]
1		UTILITY OPERATING INCOME:			
2					
3	454	RENT FROM ELECTRIC PROPERTY	$ -	$ -	0.969124
4					
5		OPERATING & MAINTENANCE EXPENSES:			
6					
7	546	OTHER POWER - OPERATION SUPERVISION & ENGINEERING	$ 466	$ 441	0.945071
8	551	OTHER POWER - MAINTENANCE SUPERVISION & ENGINEERING	296	280	0.943471
9	553	OTHER POWER - MAINTENANCE GENERATING & ELECTRIC PLANT	118	111	0.943360
10	554	OTHER POWER - MAINTENANCE MISC OTHER POWER GENERATION	118	111	0.942812
11		TOTAL OTHER POWER GENERATION OPERATING EXPENSES	$ 998	$ 942	0.944128
12					
13	560 - 573	TRANSMISSION	$ -	$ -	
14					
15	924	A&G EXP - PROPERTY INSURANCE	$ 290	$ 279	0.963214
16	925	A&G EXP - INJURIES AND DAMAGES	1	1	0.969124
17	926	A&G EXP - EMP PENSIONS & BENEFITS	41	40	0.969124
18		TOTAL ADMINISTRATIVE & GENERAL EXPENSES	$ 333	$ 321	0.963975
19					
20		TOTAL OPERATING & MAINTENANCE EXPENSES	$ 1,331	$ 1,263	0.949094
21					
22		DEPRECIATION EXPENSES:			
23					
24	403 & 404	DEPR & AMORT EXP - OTH PROD	$ 12,158	$ 11,473	0.943622
25	403 & 404	DEPR & AMORT EXP - TRANS	544	493	0.904796
26	403 & 404	DEPR & AMORT EXP - TRANS - GSU	114	109	0.949591
27		TOTAL DEPRECIATION & AMORTIZATION EXPENSES	$ 12,817	$ 12,074	0.942026
28					
29		TAXES OTHER THAN INCOME TAXES:			
30					
31	408	TAX OTH TH INC TAX - REAL & PERS PROPERTY TAX	$ 2,002	$ 1,932	0.965076
32	408	TAX OTH TH INC TAX - FEDERAL UNEMPLOYMENT TAXES	0	0	0.969124
33	408	TAX OTH TH INC TAX - STATE UNEMPLOYMENT TAXES	0	0	0.969124
34	408	TAX OTH TH INC TAX - FICA (SOCIAL SECURITY)	20	19	0.969124
35		TOTAL TAXES OTHER THAN INCOME TAXES	$ 2,022	$ 1,952	0.965117
36					
37		OPERATING INCOME TAXES:			
38					
39	409.1	INCOME TAXES - UTILITY OPER INCOME - CURRENT FEDERAL	$ (134,239)	$ (126,923)	0.945496
40	409.1	INCOME TAXES - UTILITY OPER INCOME - CURRENT STATE	(9,471)	(8,955)	0.945496
41	410.1	INCOME TAXES - DEFERRED FEDERAL	30,427	28,768	0.945496
42	411.1	INCOME TAXES - DEFERRED STATE	8,433	7,973	0.945496
43	411.1	INVESTMENT TAX CREDIT ADJUSTMENTS	96,695	91,424	0.945496
44		TOTAL OPERATING INCOME TAXES	$ (8,156)	$ (7,712)	0.945496
45					
46		NET OPERATING INCOME/(LOSS)	$ (8,013)	$ (7,577)	0.945496
47					
48					
49		NOTE:			
50		[1] Based on FPL's most recent cost of service calculations.			

FLORIDA POWER & LIGHT COMPANY
2020 SoBRA
ACCUMULATED DEFERRED INCOME TAX CALCULATION

Line No.	Month	(1) Activity [1] ($000s)	(2) Acct 282 Ledger Balance ($000s)	(3) Days to Prorate	(4) Future Days in Test Period	(5) Prorated Monthly Activity (1)*(4)/Total (3) ($000s)	(6) Acct 282 Prorated Balance ($000s)
1							
2							
3	Beg Balance - Apr 30, 2020		$ 1,957				$ 1,957
4							
5	May-20	$ (15,719)	$ (13,763)	31	335	$ (14,427)	$ (12,471)
6	Jun-20	227	(13,536)	30	305	189	(12,281)
7	Jul-20	227	(13,309)	31	274	170	(12,111)
8	Aug-20	227	(13,083)	31	243	151	(11,960)
9	Sep-20	227	(12,856)	30	213	132	(11,828)
10	Oct-20	227	(12,629)	31	182	113	(11,715)
11	Nov-20	227	(12,402)	30	152	94	(11,620)
12	Dec-20	227	(12,176)	31	121	75	(11,545)
13	Jan-21	(25,407)	(37,583)	31	90	(6,265)	(17,810)
14	Feb-21	227	(37,356)	28	62	39	(17,772)
15	Mar-21	227	(37,129)	31	31	19	(17,752)
16	Apr-21	227	(36,903)	30	1	1	(17,752)
17	Total	$ (38,859)		365			
18							
19							
20	Prorated Balance						$ (17,752) [2]
21							
22							

23 NOTE:
24 [1] Includes the impact associated tax depreciation for the years ended December 31, 2020 and December 31, 2021.
25 [2] Prorated balance is reflected as a reduction to rate base on Page 2, Line 26.

FLORIDA POWER & LIGHT COMPANY
2017 SoBRA
FIRST YEAR ANNUALIZED REVENUE REQUIREMENT[1]
($000)

Line No.	(1) Description	(2) Reference	(3) Initial SoBRA [2] Amount	(4) Final SoBRA [3] Amount	(5) Difference
1	Jurisdictional Adjusted Rate Base	Page 2	$ 343,848	$ 320,550	$ (23,298)
2	Rate of Return on Rate Base		8.30%	8.30%	8.30%
3	Required Jurisdictional Net Operating Income	Line 1 x Line 2	$ 28,535	$ 26,602	$ (1,933)
4	Required Net Operating Income		(8,590)	(8,590)	0
5	Net Operating Income Deficiency (Excess)	Line 3 - Line 4	$ 37,125	$ 35,192	$ (1,933)
6	Net Operating Income Multiplier[4]		1.63025	1.63025	1.63025
7	Revenue Requirement	Line 5 x Line 6	$ 60,523	$ 57,371	$ (3,152)
8					
9	NOTES:				
10	[1] Represents the revenue requirement for projected 12-month period for the 2017 Project.				
11	[2] Initial SoBRA calculation approved by the Commission in Order No. PSC-2018-0028-FOF-EI, Docket No. 20180001-EI (issued on January 8, 2018).				
12	[3] Based on inputs included in the initial SoBRA in column 3, except projected capital costs were replaced with final actual capital costs. See Page 2 for details on the final actual capital costs.				
13	[4] Represents the net operating income multiplier from page 9 of Exhibit KO-20, Docket No. 160021-EI.				

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 29
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: L. Fuentes LF-2

FLORIDA POWER & LIGHT COMPANY
2017 SoBRA
JURISDICTIONAL ADJUSTED RATE BASE
13-MONTH AVERAGE
($000)

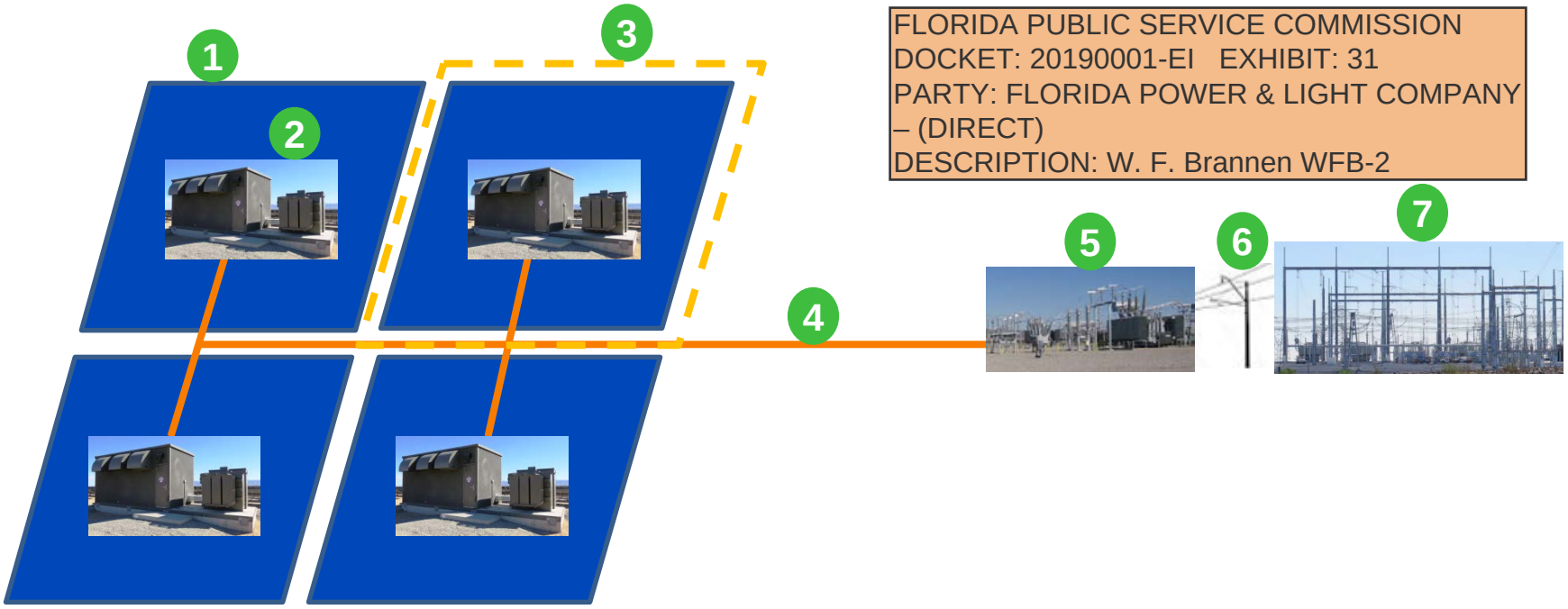
Line No.	(1) Description	Initial SoBRA[1] (2) Total Company	(3) FPSC Jurisdictional	(4) Jurisdictional Factor[3]	Final SoBRA[2] (5) Total Company	(6) FPSC Jurisdictional	(7) Jurisdictional Factor[3]
1							
2	PLANT IN SERVICE:						
3							
4	ELECTRIC PLANT IN SERVICE - OTHER PRODUCTION	$ 391,674	$ 374,696	0.956652	$ 352,740	$ 337,450	0.956652
5							
6	ELECTRIC PLANT IN SERVICE - TRANSMISSION	$ 11,506	$ 10,217	0.887974	$ 22,805	$ 20,250	0.887974
7	ELECTRIC PLANT IN SERVICE - TRANSMISSION - GSU's	3,383	3,212	0.949382	7,355	6,982	0.949382
8	TOTAL ELECTRIC PLANT IN SERVICE - TRANSMISSION	$ 14,889	$ 13,428	0.901927	$ 30,159	$ 27,232	0.901927
9							
10	NON-DEPRECIABLE PROPERTY (LAND)	$ 12,269	$ 11,737	0.956652	$ 12,420	$ 11,881	0.956652
11							
12	TOTAL PLANT IN SERVICE	$ 418,832	$ 399,861	0.954706	$ 395,319	$ 376,563	0.954706
13							
14							
15	ACCUMULATED PROVISION FOR DEPRECIATION:						
16							
17	ACCUM PROVISION FOR DEPRECIATION - OTHER PRODUCTION	$ 6,600	$ 6,314	0.956652	$ 6,600	$ 6,314	0.956652
18							
19	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION	$ 115	$ 102	0.887974	$ 115	$ 102	0.887974
20	ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION - GSU	45	42	0.949382	45	42	0.949382
21	TOTAL ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION	$ 160	$ 145	0.905143	$ 160	$ 145	0.905143
22							
23	TOTAL ACCUMULATED PROVISION FOR DEPRECIATION	$ 6,759	$ 6,458	0.955435	$ 6,759	$ 6,458	0.955435
24							
25							
26	ACCUMULATED DEFERRED INCOME TAXES	$ (51,907)	$ (49,555)	0.954694	$ (51,907)	$ (49,555)	0.954694
27							
28	TOTAL RATE BASE	$ 360,166	$ 343,848	0.954694	$ 336,653	$ 320,550	0.954694
29							
30							
31	NOTES:						
32	[1] Reflects projected rate base included in the Initial SoBRA calculation approved by the Commission in Order No. PSC-2018-0028-FOF-EI, Docket No. 20180001-EI (issued on January 8, 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.						
34	[3] Based on FPL's cost of service calculations prepared for the 2017 budget cycle.						

List of FPL Universal PV Solar Centers in Service

Solar Energy Center	Capacity (MW_{AC})	In-Service Date
DeSoto	25.0	October 27, 2009
Space Coast	10.0	April 16, 2010
Babcock Ranch	74.5	December 31, 2016
Citrus	74.5	December 31, 2016
Manatee	74.5	December 31, 2016
Coral Farms	74.5	January 1, 2018
Horizon	74.5	January 1, 2018
Wildflower	74.5	January 1, 2018
Indian River	74.5	January 1, 2018
Loggerhead	74.5	March 1, 2018
Barefoot Bay	74.5	March 1, 2018
Hammock	74.5	March 1, 2018
Blue Cypress	74.5	March 1, 2018
Interstate	74.5	January 31, 2019
Miami-Dade	74.5	January 31, 2019
Pioneer Trail	74.5	January 31, 2019
Sunshine Gateway	74.5	January 31, 2019
FPL Total	**1,152.5**	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 30
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: W. F. Brannen WFB-1

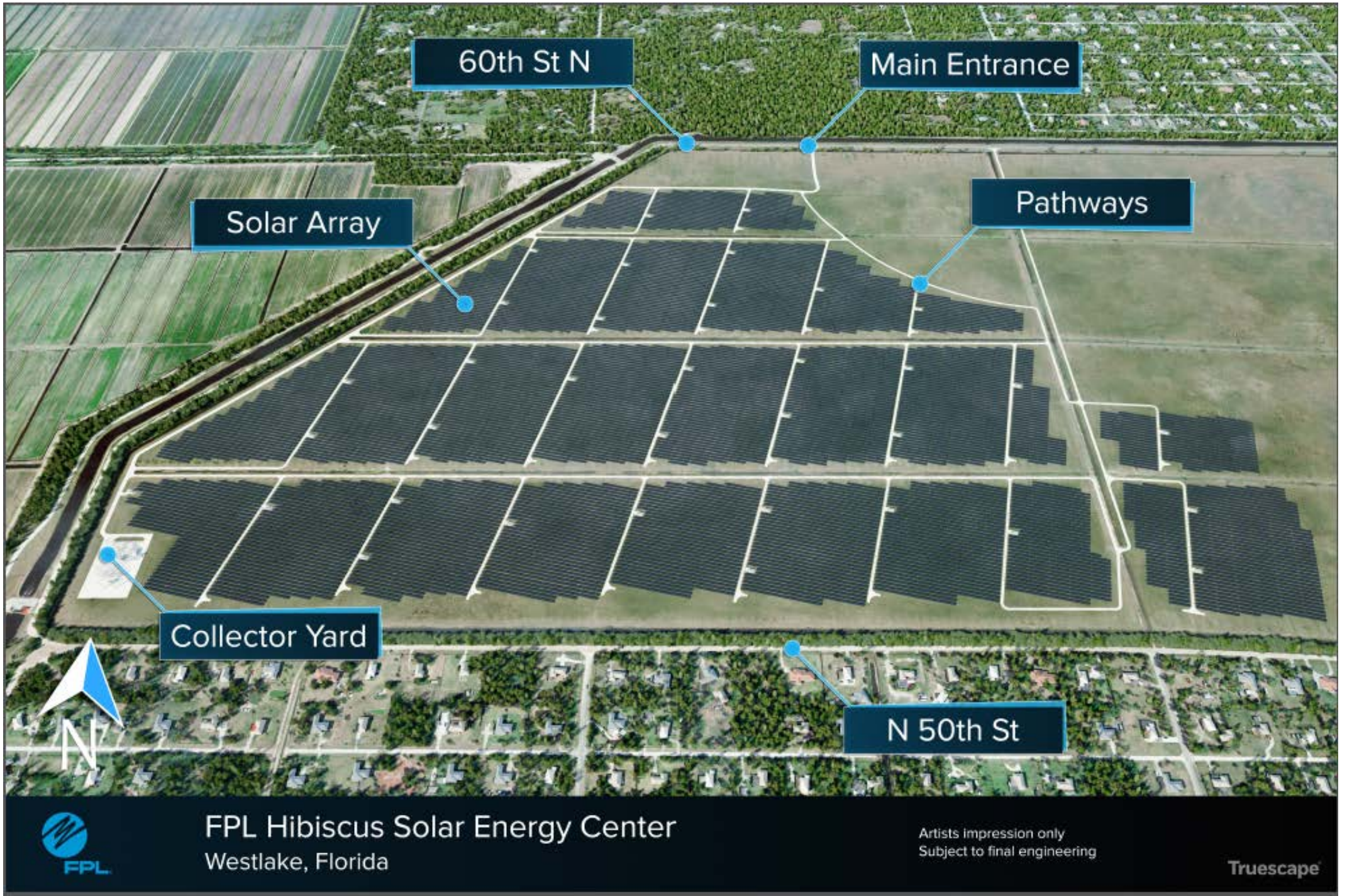
Typical Solar Energy Center Block Diagram



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 31
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: W. F. Brannen WFB-2

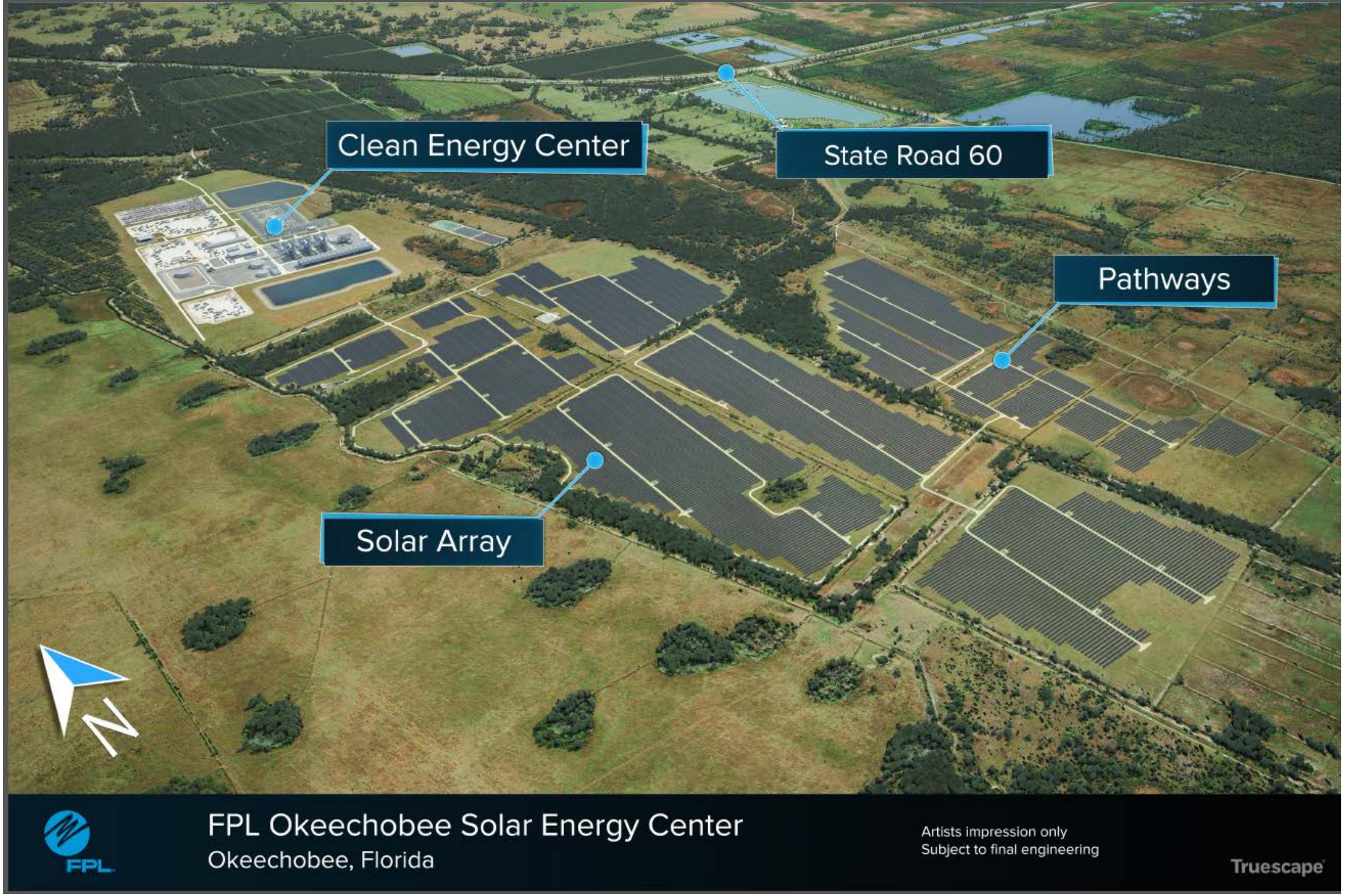
1. Array of PV Panels
2. Inverter/Medium Voltage Transformer
3. Inverter Block
4. AC Collection System
5. Switchyard and Power Step-up Transformer
6. Generation Tie Line
7. Interconnection Substation

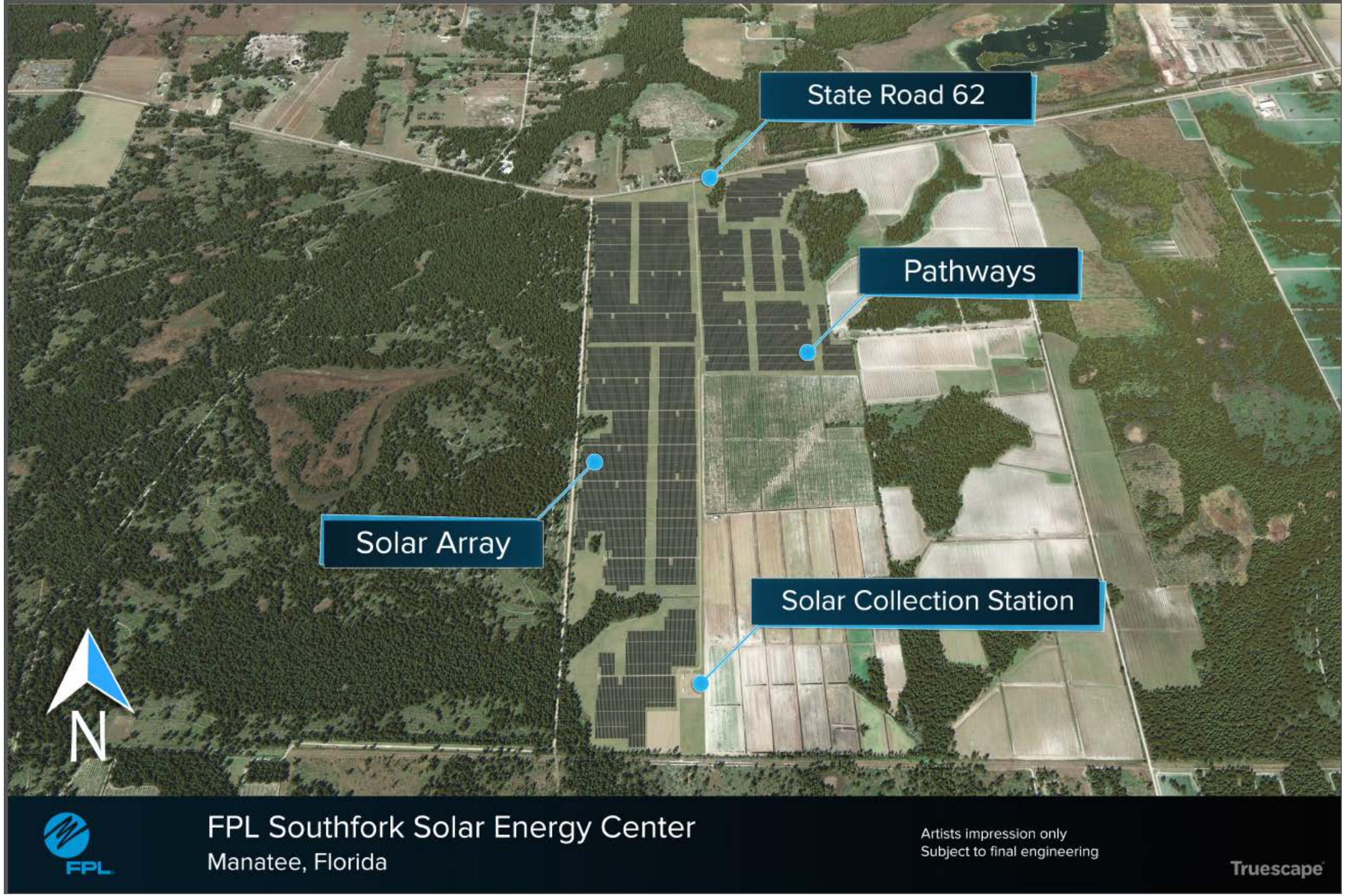
Docket No. 20190001-EI
Typical Solar Energy Center Block Diagram
Exhibit WFB-2, Page 1 of 1



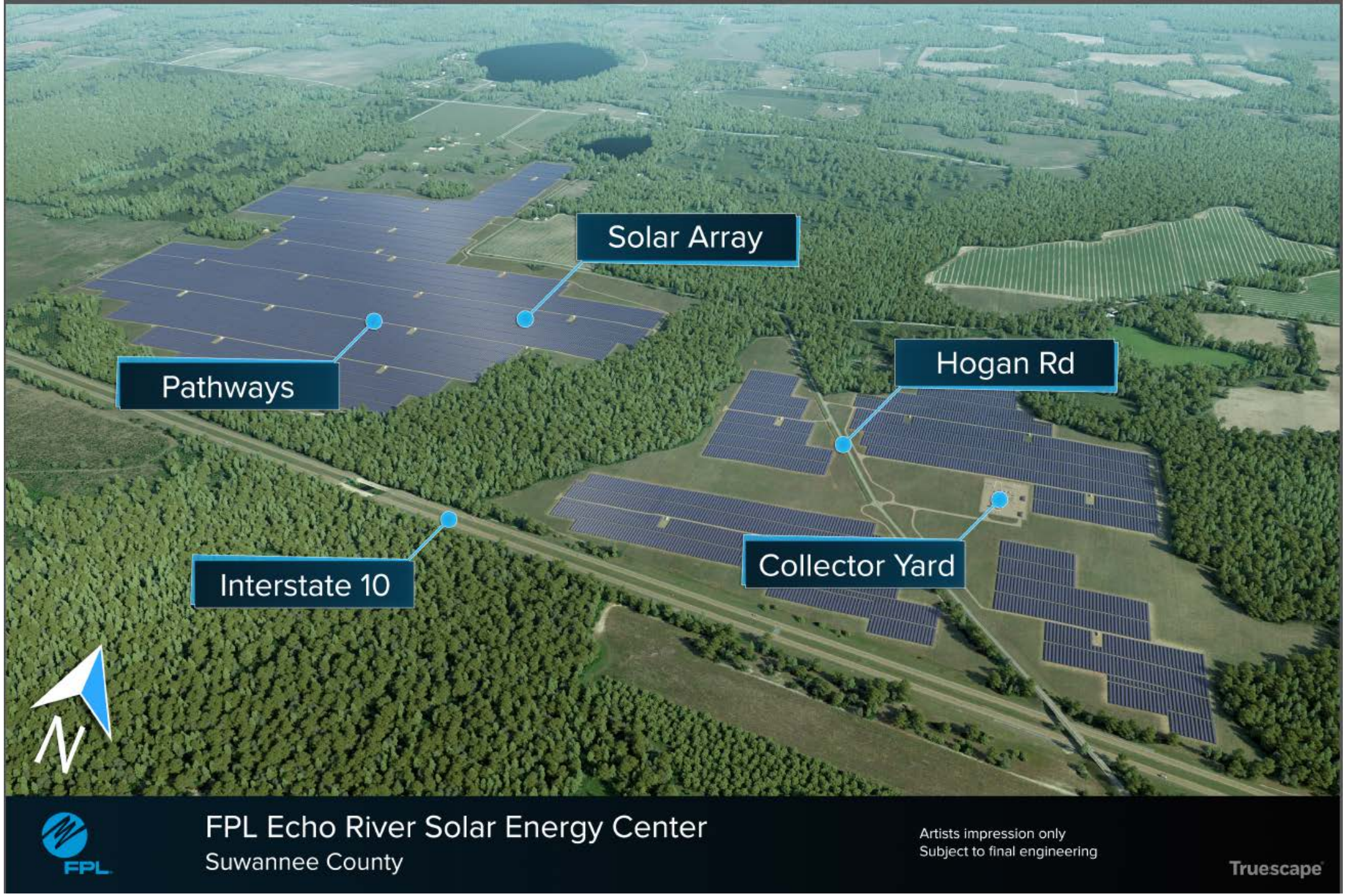
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 32
PARTY: FLORIDA POWER & LIGHT
COMPANY – (DIRECT)
DESCRIPTION: W. F. Brannen WFB-3

Docket No. 20190001-EI
Renderings of 2020 Solar Energy Centers
Exhibit WFB-3, Page 1 of 4


Clean Energy Center
State Road 60
Pathways
Solar Array
N
FPL
FPL Okeechobee Solar Energy Center
Okeechobee, Florida
Artists impression only
Subject to final engineering
Truescape



Docket No. 20190001-EI
Renderings of 2020 Solar Energy Centers
Exhibit WFB-3, Page 3 of 4


Solar Array
Pathways
Hogan Rd
Interstate 10
Collector Yard
N
FPL
FPL Echo River Solar Energy Center
Suwannee County
Artists impression only
Subject to final engineering
Truescape

Specifications for 2020 Solar Energy Centers
Hibiscus

The following table sets forth the base-line specifications used to develop the estimated installed cost for the Hibiscus Energy Center.

Specifications for FPL 74.5 MW_{AC} Hibiscus Solar Energy Center	
Peak Alternating Current Output	74.5 MW_{AC}
Total Installed Direct Current Capacity	108.03 MW_{DC}
PV Panel Suppliers	First Solar
PV Panel Technologies	Thin film CdTE semiconductor
PV Panel Voltage (V)	1,500
Average PV Panel Power Ratings (W_{DC})	420
Number of Panels (Approximate)	257,200
PV Panel Support System	Fixed-tilt
PV Panel Support System Material	Structural Steel Shapes
Inverter DC Input (MW_{DC})	4.70
DC/AC Ratio	1.45
Number of Power Conversion Units (PCU)	23
PCU Supplier	SMA
Inverter Type	MVPS-4000-S2
Inverter Rating (MVA/V)	4.0/600
Medium Voltage Transformers Per PCU	1
Medium Voltage Transformer Supplier	TBD
Medium Voltage Transformer Type	3-Phase, 60 Hz, 3-Windings
Medium Voltage Transformer Rating (MVA)	4.0
Number of Inverters	23
Inverter Capacity Installed (MVA)	86.5 @ 35° C
Number of Medium Voltage Transformers	23
Medium Voltage Transformer Capacity Installed (MVA)	92
Number of Panels Per PCU Block (Approximate)	11,180
DC Input Per PCU Block (MW_{DC})	4.70
Step-up Power Transformer Supplier	SMIT
Step-up Power Transformer Type	3-Phase, 60 Hz
Step-up Power Transformer Ratings	241.5 kV, 85 MVA

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 33
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: W. F. Brannen WFB-4

Specifications for 2020 Solar Energy Centers
Okeechobee

The following table sets forth the base-line specifications used to develop the estimated installed cost for the Okeechobee Energy Center.

Specifications for FPL 74.5 MW_{AC} Okeechobee Solar Energy Center	
Peak Alternating Current Output	74.5 MW_{AC}
Total Installed Direct Current Capacity	111.75 MW_{DC}
PV Panel Suppliers	First Solar
PV Panel Technologies	Thin film CdTE semiconductor
PV Panel Voltage (V)	1,500
Average PV Panel Power Ratings (W_{DC})	430
Number of Panels (Approximate)	259,900
PV Panel Support System	Fixed-tilt
PV Panel Support System Material	Structural Steel Shapes
Inverter DC Input (MW_{DC})	4.66
DC/AC Ratio	1.50
Number of Power Conversion Units (PCU)	24
PCU Supplier	SMA
Inverter Type	MVPS-4000-S2
Inverter Rating (MVA/V)	4.0/600
Medium Voltage Transformers Per PCU	1
Medium Voltage Transformer Supplier	TBD
Medium Voltage Transformer Type	3-Phase, 60 Hz, 3-Windings
Medium Voltage Transformer Rating (MVA)	4.0
Number of Inverters	24
Inverter Capacity Installed (MVA)	90.2 @ 35º C
Number of Medium Voltage Transformers	24
Medium Voltage Transformer Capacity Installed (MVA)	96
Number of Panels Per PCU Block (Approximate)	10,830
DC Input Per PUC Block (MW_{DC})	4.66
Step-up Power Transformer Supplier	HICO America, Inc.
Step-up Power Transformer Type	3-Phase, 60 Hz
Step-up Power Transformer Ratings	26 kV, 85 MVA

Specifications for 2020 Solar Energy Centers
Southfork

The following table sets forth the base-line specifications used to develop the estimated installed cost for the Southfork Energy Center.

Specifications for FPL 74.5 MW_{AC} Southfork Solar Energy Center	
Peak Alternating Current Output	74.5 MW_{AC}
Total Installed Direct Current Capacity	108.03 MW_{DC}
PV Panel Suppliers	Jinko
PV Panel Technologies	72 cell, mono-crystalline
PV Panel Voltage (V)	1,500
Average PV Panel Power Ratings (W_{DC})	395
Number of Panels (Approximate)	273,500
PV Panel Support System	Single-axis tracker
PV Panel Support System Material	Structural Steel Shapes
Inverter DC Input (MW_{DC})	4.91
DC/AC Ratio	1.45
Number of Power Conversion Units (PCU)	22
PCU Supplier	SMA
Inverter Type	SMA MVPS-4200-S2
Inverter Rating (MVA/V)	4.2/630
Medium Voltage Transformers Per PCU	1
Medium Voltage Transformer Supplier	TBD
Medium Voltage Transformer Type	3-Phase, 60 Hz, 2-Windings
Medium Voltage Transformer Rating (MVA)	4.2
Number of Inverters	22
Inverter Capacity Installed (MVA)	86.9 @ 35^{o} C
Number of Medium Voltage Transformers	22
Medium Voltage Transformer Capacity Installed (MVA)	92.4
Number of Panels Per PCU Block (Approximate)	12,430
DC Input Per PUC Block (MW_{DC})	4.91
Step-up Power Transformer Supplier	SMIT
Step-up Power Transformer Type	3-Phase, 60 Hz
Step-up Power Transformer Ratings	241.5 kV, 85 MVA

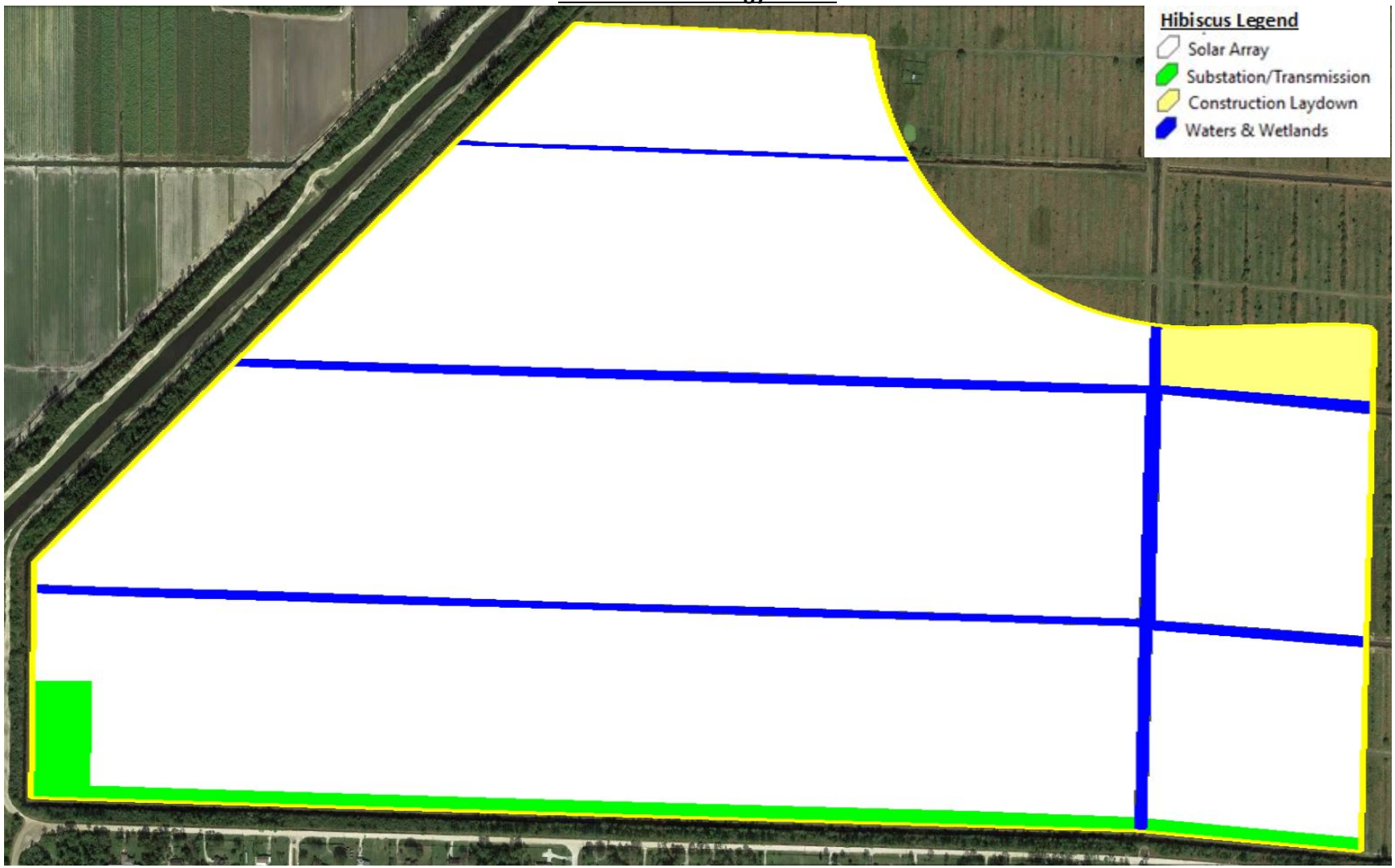
Specifications for 2020 Solar Energy Centers
Echo River

The following table sets forth the base-line specifications used to develop the estimated installed cost for the Echo River Energy Center.

Specifications for FPL 74.5 MW_{AC} Echo River Solar Energy Center	
Peak Alternating Current Output	74.5 MW_{AC}
Total Installed Direct Current Capacity	108.03 MW_{DC}
PV Panel Suppliers	Jinko
PV Panel Technologies	72-cell, mono-crystalline
PV Panel Voltage (V)	1,500
Average PV Panel Power Ratings (W_{DC})	395
Number of Panels (Approximate)	273,500
PV Panel Support Structure	Single-axis tracker
PV Panel Support System Material	Structural Steel Shapes
Inverter DC Input (MW_{DC})	4.91
DC/AC Ratio	1.45
Number of Power Conversion Units (PCU)	22
PCU Supplier	SMA
Inverter Type	MVPS-4200-S2
Inverter Rating (MVA/V)	4.2/630
Medium Voltage Transformers Per PCU	1
Medium Voltage Transformer Supplier	TBD
Medium Voltage Transformer Type	3-Phase, 60 Hz, 2-Windings
Medium Voltage Transformer Rating (MVA)	4.2
Number of Inverters	22
Inverter Capacity Installed (MVA)	86.9 @ 35^{o} C
Number of Medium Voltage Transformers	22
Medium Voltage Transformer Capacity Installed (MVA)	92.4
Number of Panels Per PCU Block (Approximate)	12,430
DC Input Per PUC Block (MW_{DC})	4.91
Step-up Power Transformer Supplier	SMIT
Step-up Power Transformer Type	3-Phase, 60 Hz
Step-up Power Transformer Ratings	117.5 kV, 85 MVA

Property Delineations, Features and Land Use of 2020 Solar Energy Centers

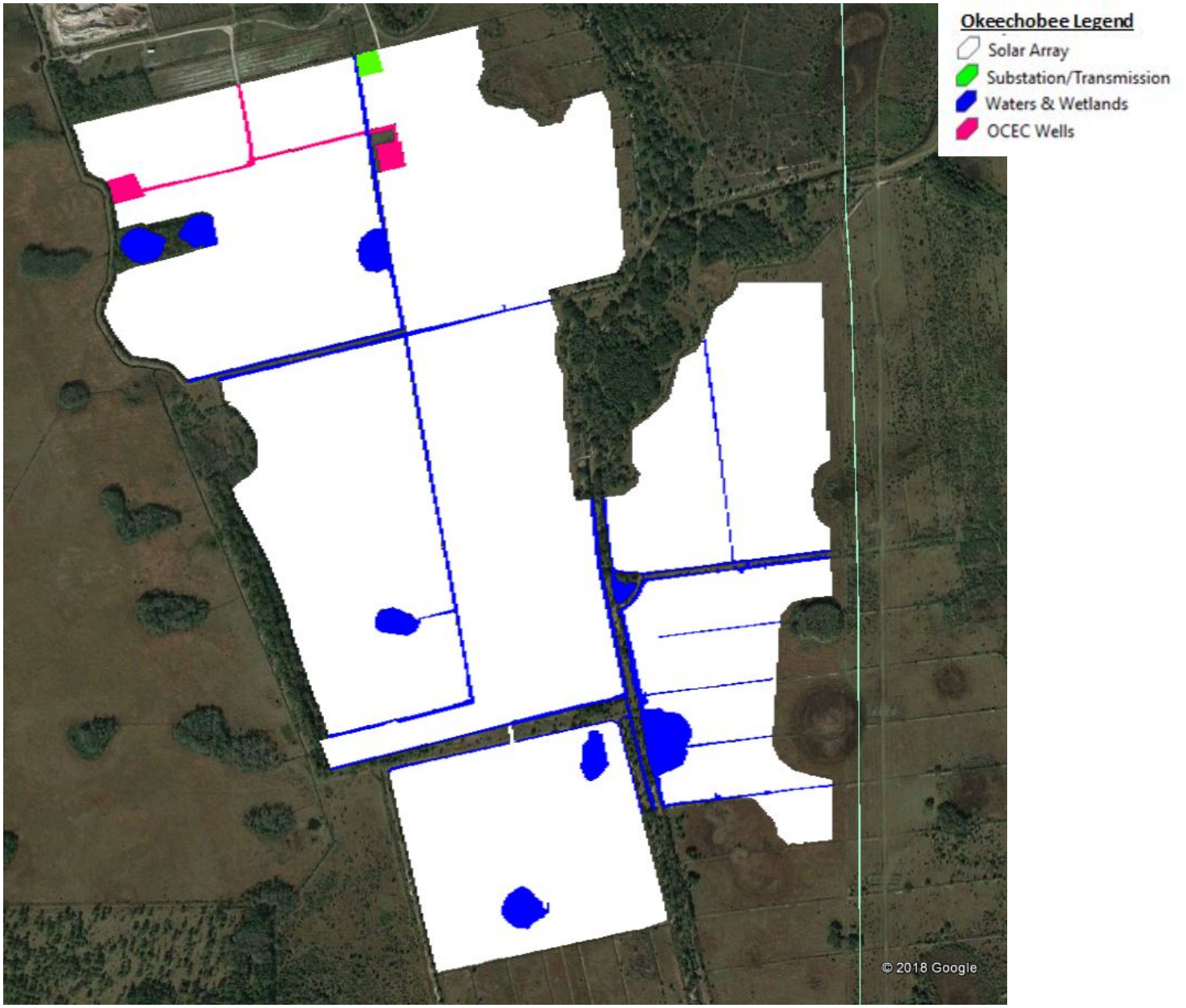
Hibiscus Solar Energy Center



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 34
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: W. F. Brannen WFB-5

Property Delineations, Features and Land Use of 2020 Solar Energy Centers

Okeechobee Solar Energy Center



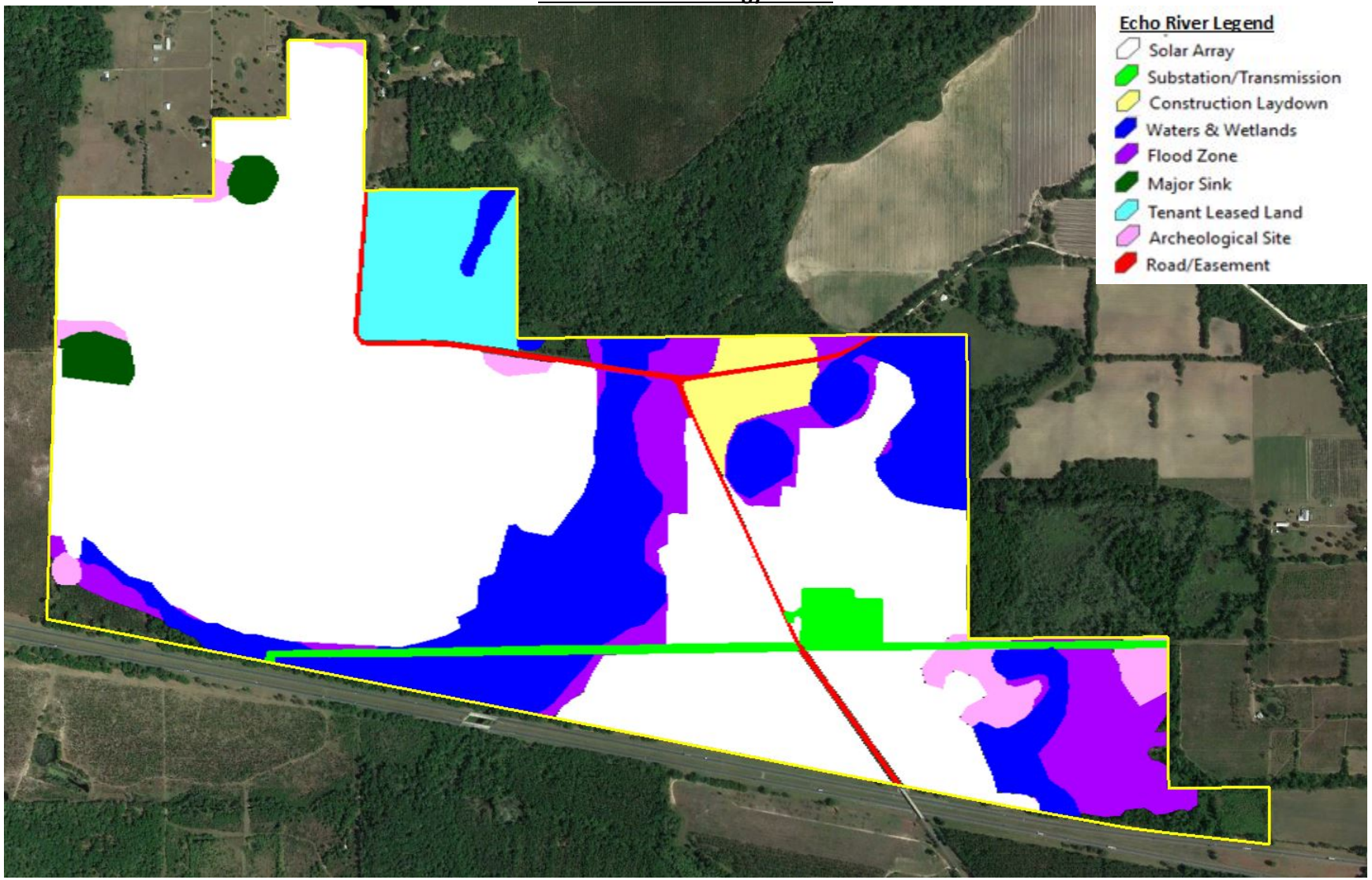
Property Delineations, Features and Land Use of 2020 Solar Energy Centers

Southfork Solar Energy Center



Property Delineations, Features and Land Use of 2020 Solar Energy Centers

Echo River Solar Energy Center



Construction Schedule for 2020 Solar Energy Centers

		Echo River		Southfork		Okeechobee		Hibiscus	
Item	**Major Activities**	**Start**	**Finish**	**Start**	**Finish**	**Start**	**Finish**	**Start**	**Finish**
1	PV panel contract		12/31/2018		12/31/2018		7/30/2018		7/30/2018
2	Power Conversion Unit contract		3/31/2019		3/31/2019		3/31/2019		3/31/2019
4	EPC contract		12/19/2018		12/19/2018		12/19/2018		12/19/2018
3	LNTP for EPC contracts		3/1/2019		3/1/2019		3/1/2019		3/1/2019
4	Contractor mobilization	5/1/2019	5/15/2019	5/1/2019	5/15/2019	5/1/2019	5/15/2019	4/1/2019	4/15/2019
5	Panel deliveries	8/23/2019	12/27/2019	8/16/2019	12/27/2019	9/13/2019	11/29/2019	8/23/2019	11/8/2019
6	Power Conversion Unit deliveries	11/1/2019	11/15/2019	11/1/2019	11/15/2019	10/1/2019	10/15/2019	11/1/2019	11/15/2019
7	Energization, Testing & Startup	4/9/2020	4/23/2020	4/9/2020	4/23/2020	4/9/2020	4/23/2020	4/9/2020	4/23/2020
8	Commence Commercial Operations	5/1/2020							

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 35
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: W. F. Brannen WFB-6

Load Forecast
December 2018

Year	Summer Peak MW	Winter Peak MW	Net Energy for Load MWh
2020	24,507	19,904	122,284,248
2021	24,668	20,264	122,369,658
2022	24,837	20,255	122,330,746
2023	25,173	20,528	122,680,361
2024	25,583	20,775	123,864,043
2025	25,939	20,932	124,440,227
2026	26,380	21,150	125,429,987
2027	26,867	21,374	126,520,149
2028	27,363	21,623	127,940,788
2029	28,008	21,889	128,967,611
2030	28,691	22,153	130,367,909
2031	29,254	22,404	131,675,941
2032	29,833	22,653	133,326,250
2033	30,407	22,900	134,288,370
2034	30,974	23,145	135,498,214
2035	31,542	23,388	136,706,457
2036	32,109	23,630	138,063,532
2037	32,657	23,871	138,932,635
2038	33,228	24,110	140,133,040
2039	33,804	24,349	141,312,242
2040	34,382	24,586	142,843,906
2041	34,771	24,825	144,980,773
2042	35,161	25,063	146,449,887
2043	35,554	25,301	147,916,439
2044	35,948	25,540	149,764,613
2045	36,344	25,779	150,844,643
2046	36,741	26,018	152,304,156
2047	37,139	26,258	153,765,649
2048	37,540	26,498	155,583,773
2049	37,943	26,738	156,652,695
2050	38,347	26,978	158,122,734

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 36
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: J. Enjamio JE-1

FPL Fuel Price Forecast
December 2018

Year	FGT Firm Gas ($/MMBTU)	Gulfstream Firm Gas ($/MMBTU)	Sabal Trail Firm Gas ($/MMBTU)	Residual Oil ($/MMBTU)	Distillate Oil ($/MMBTU)	Scherer 4 Coal Price ($/MMBTU)
2020	2.74	2.67	2.74	10.92	14.10	2.59
2021	2.71	2.64	2.72	12.27	15.61	2.65
2022	2.80	2.73	2.80	11.31	14.65	2.72
2023	3.02	2.95	3.01	10.83	14.62	2.80
2024	3.37	3.29	3.35	11.01	15.02	2.86
2025	3.68	3.60	3.65	11.64	15.54	2.93
2026	3.98	3.91	3.95	11.93	15.84	3.00
2027	4.19	4.11	4.15	12.17	16.12	3.06
2028	4.37	4.29	4.33	12.40	16.39	3.13
2029	4.54	4.46	4.49	12.65	16.71	3.19
2030	4.68	4.60	4.63	12.93	17.02	3.25
2031	4.80	4.72	4.75	13.18	17.33	3.31
2032	4.92	4.83	4.86	13.40	17.65	3.38
2033	5.02	4.94	4.97	13.64	17.98	3.45
2034	5.13	5.05	5.07	13.87	18.31	3.52
2035	5.23	5.15	5.17	14.11	18.67	3.60
2036	5.34	5.25	5.27	14.36	19.01	3.67
2037	5.44	5.35	5.37	14.62	19.35	3.75
2038	5.54	5.45	5.47	14.88	19.70	3.83
2039	5.65	5.56	5.58	15.14	20.06	3.91
2040	5.76	5.67	5.68	15.42	20.42	3.99
2041	5.82	5.73	5.75	15.49	20.45	4.08
2042	5.88	5.79	5.81	15.56	20.48	4.18
2043	5.95	5.86	5.87	15.63	20.51	4.27
2044	6.01	5.92	5.93	15.70	20.54	4.36
2045	6.08	5.99	6.00	15.78	20.57	4.46
2046	6.14	6.05	6.06	15.85	20.60	4.55
2047	6.21	6.12	6.13	15.92	20.64	4.65
2048	6.28	6.19	6.19	16.00	20.67	4.75
2049	6.35	6.26	6.26	16.07	20.70	4.85
2050	6.42	6.32	6.33	16.14	20.73	4.95

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 37
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: J. Enjamio JE-2

Resource Plans - Units Added

Year	No 2020 Project Plan	2020 Project Plan
2020	447 MW Solar Together; 100 MW Battery	2020 Project (298 MW); 447 MW FPL SolarTogether
2021	1,043 MW FPL SolarTogether	1,043 MW FPL SolarTogether
2022	Dania Beach Energy Center, 469 MW Manatee battery, Manatee 1-2 retire,	Dania Beach Energy Center, 469 MW Manatee battery, Manatee 1-2 retire,
2023	Greenfield 469 MW CT Unit	Greenfield 469 MW CT Unit
2024	Greenfield 1,886 MW CC Unit	Greenfield 1,886 MW CC Unit
2025		
2026		
2027		
2028	Greenfield 1,886 MW CC Unit	Greenfield 1,886 MW CC Unit
2029		
2030	Greenfield 704 MW CT Unit	Greenfield 704 MW CT Unit
2031	Equalizing 266 MW CC Unit	Equalizing 180 MW CC Unit

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 38
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: J. Enjamio JE-3

CPVRR - Costs and (Benefits)

Solar Revenue Requirements		**Non-Solar (Avoided) Generation Costs**				**Avoided System Costs**			
Generation Capital (Millions)	Fixed O&M (Millions)	Generation Capital (Millions)	Fixed O&M (Millions)	Transmission Interconnection (Millions)	Capital Replacement (Millions)	System Net Fuel (Millions)	Startup + VOM (Millions)	Emission (Millions)	Total CPVRR (Millions)
$402	$20	($79)	($15)	($2)	($4)	($323)	($6)	($20)	**($26)**

* Negative ( ) indicates savings to FPL customers

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 39
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: J. Enjamio JE-4

FLORIDA POWER & LIGHT COMPANY
2020 SOBRA FACTOR CALCULATION

2020 SoBRA Factor Calculation		**($Million)**	**Source**
(A)	Jurisdictional Annualized Revenue Requirement	$50.491	Exhibit LF-1 as Filed
(B)	Total Retail Base Revenues From the Sales of Electricity	$6,896.706	Exhibit EJA-2 Page 1 of 1
(C)	SoBRA Factor [(A) / (B)]	0.732%	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 40
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: E. J. Anderson EJA-1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 41
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: E. J. Anderson EJA-2

FLORIDA POWER & LIGHT COMPANY
RETAIL BASE REVENUES
12 MONTHS BEGINNING MAY 2020

Customer Class	2020 May	Jun	Jul	Aug	Sep	Oct	Nov
Residential	350,335,713	404,626,015	444,182,207	448,129,060	432,812,183	394,816,074	322,944,125
Commercial	199,539,812	205,784,347	210,708,384	209,791,519	209,222,725	205,730,540	190,444,432
Industrial	7,516,655	7,758,277	7,542,994	7,387,350	7,557,008	7,435,126	7,411,442
Street & Highway	5,437,738	5,365,356	5,378,392	5,798,606	5,620,310	5,168,632	5,966,657
Other	135,616	123,339	128,474	120,711	132,425	143,215	145,138
Railroads & Railways	330,207	316,316	335,418	353,711	342,959	321,988	322,571
Total Jurisdictional Billed Revenue	563,295,741	623,973,650	668,275,868	671,580,956	655,687,610	613,615,575	527,234,366
CILC/CDR Incentive	5,802,488	8,774,123	6,668,814	6,728,098	6,054,485	5,844,162	5,519,475
Unbilled Revenue	383,774	425,114	455,298	457,549	446,721	418,057	359,206
Total Retail Base Revenues From the Sales of Electricity	$ 569,482,004	$ 633,172,888	$ 675,399,980	$ 678,766,604	$ 662,188,816	$ 619,877,794	$ 533,113,047

Customer Class	2020/2021 Dec	Jan	Feb	Mar	Apr	12 Months Ending
Residential	301,983,386	320,852,261	280,263,043	289,087,861	314,139,469	4,304,171,399
Commercial	186,228,451	187,563,243	172,039,328	181,381,009	193,725,627	2,352,159,418
Industrial	7,476,861	7,507,331	7,629,982	7,542,103	7,616,013	90,381,142
Street & Highway	5,558,925	5,817,439	5,324,449	6,485,188	6,068,239	67,989,931
Other	138,859	128,677	139,863	144,082	132,012	1,612,409
Railroads & Railways	322,670	302,580	310,954	300,287	306,521	3,866,181
Total Jurisdictional Billed Revenue	501,709,152	522,171,531	465,707,619	484,940,531	521,987,881	6,820,180,479
CILC/CDR Incentive Credit	8,138,927	5,229,813	5,669,622	5,148,207	5,452,467	75,030,682
Unbilled Revenue	341,815	355,756	317,288	330,391	355,631	4,646,602
Total Retail Base Revenues From the Sales of Electricity	$ 510,189,894	$ 527,757,100	$ 471,694,529	$ 490,419,129	$ 527,795,979	$ 6,899,857,764
Adjustment for 2017 Project True-Up						(3,152,009) *
Adjusted Total Retail Base Revenues From the Sales of Electricity						$ 6,896,705,755

* Refer to Exhibit EJA-4 Page 1 of 1

Totals may not add due to rounding

Docket No. 20190001-EI
Projected Retail Base Revenues for May 1, 2020
Exhibit EJA-2, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 42
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: E. J. Anderson EJA-3

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
MAY 1, 2020 SoBRA RATES

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	RS-1	Residential Service				
2		Customer Charge/Minimum	$8.28	$8.34	$0.06	0.7%
3						
4		Base Energy Charge (¢ per kWh)				
5		First 1,000 kWh	6.115	6.160	0.0450	0.7%
6		All additional kWh	7.170	7.222	0.0520	0.7%
7						
8						
9	RTR-1	Residential Service -Time of Use				
10		Customer Charge/Minimum	$8.28	$8.34	$0.06	0.7%
11						
12		Base Energy Charge (¢ per kWh)				
13		On-Peak	10.909	10.989	0.080	0.7%
14		Off-Peak	(4.853)	(4.889)	(0.036)	0.7%
15						
16						
17	GS-1	General Service - Non Demand (0-20 kW)				
18		Customer Charge/Minimum				
19		Metered	$10.54	$10.62	$0.08	0.8%
20		Unmetered Service Credit	($5.26)	($5.30)	($0.04)	0.8%
21						
22		Base Energy Charge (¢ per kWh)	5.969	6.013	0.044	0.7%
23						
24						
25	GST-1	General Service - Non Demand - Time of Use (0-20 kW)				
26		Customer Charge/Minimum	$10.54	$10.62	$0.08	0.8%
27						
28		Base Energy Charge (¢ per kWh)				
29		On-Peak	11.022	11.103	0.081	0.7%
30		Off-Peak	3.774	3.802	0.028	0.7%
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* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	GSD-1	General Service Demand (21-499 kW)				
2		Customer Charge	$26.31	$26.50	$0.19	0.7%
3						
4		Demand Charge ($/kW)	$9.91	$9.98	$0.07	0.7%
5						
6		Base Energy Charge (¢ per kWh)	2.206	2.222	0.016	0.7%
7						
8						
9	GSDT-1	General Service Demand - Time of Use (21-499 kW)				
10		Customer Charge	$26.31	$26.50	$0.19	0.7%
11						
12		Demand Charge - On-Peak ($/kW)	$9.91	$9.98	$0.07	0.7%
13						
14		Base Energy Charge (¢ per kWh)				
15		On-Peak	4.500	4.533	0.033	0.7%
16		Off-Peak	1.190	1.199	0.009	0.8%
17						
18						
19	GSLD-1	General Service Large Demand (500-1999 kW)				
20		Customer Charge	$78.87	$79.45	$0.58	0.7%
21						
22		Demand Charge ($/kW)	$12.10	$12.19	$0.09	0.7%
23						
24		Base Energy Charge (¢ per kWh)	1.742	1.755	0.013	0.7%
25						
26						
27	GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)				
28		Customer Charge	$78.87	$79.45	$0.58	0.7%
29						
30		Demand Charge - On-Peak ($/kW)	$12.10	$12.19	$0.09	0.7%
31						
32		Base Energy Charge (¢ per kWh)				
33		On-Peak	2.852	2.873	0.021	0.7%
34		Off-Peak	1.257	1.266	0.009	0.7%
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* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CS-1	Curtailable Service (500-1999 kW)				
2		Customer Charge	$105.17	$105.94	$0.77	0.7%
3						
4		Demand Charge ($/kW)	$12.10	$12.19	$0.09	0.7%
5						
6		Base Energy Charge (¢ per kWh)	1.742	1.755	0.013	0.7%
7						
8		Monthly Credit ($ per kW)	($2.04)	($2.05)	($0.01)	0.5%
9						
10		Charges for Non-Compliance of Curtailment Demand				
11		Rebilling for last 36 months (per kW)	$2.04	$2.05	$0.01	0.5%
12		Penalty Charge-current month (per kW)	$4.38	$4.41	$0.03	0.7%
13		Early Termination Penalty charge (per kW)	$1.29	$1.30	$0.01	0.8%
14						
15	CST-1	Curtailable Service -Time of Use (500-1999 kW)				
16		Customer Charge	$105.17	$105.94	$0.77	0.7%
17						
18		Demand Charge - On-Peak ($/kW)	$12.10	$12.19	$0.09	0.7%
19						
20		Base Energy Charge (¢ per kWh)				
21		On-Peak	2.852	2.873	0.021	0.7%
22		Off-Peak	1.257	1.266	0.009	0.7%
23						
24		Monthly Credit ($ per kW)	($2.04)	($2.05)	($0.01)	0.5%
25						
26		Charges for Non-Compliance of Curtailment Demand				
27		Rebilling for last 36 months (per kW)	$2.04	$2.05	$0.01	0.5%
28		Penalty Charge-current month (per kW)	$4.38	$4.41	$0.03	0.7%
29		Early Termination Penalty charge (per kW)	$1.29	$1.30	$0.01	0.8%
30						
31	GSLD-2	General Service Large Demand (2000 kW +)				
32		Customer Charge	$236.44	$238.17	$1.73	0.7%
33						
34		Demand Charge ($/kW)	$12.60	$12.69	$0.09	0.7%
35						
36		Base Energy Charge (¢ per kWh)	1.568	1.579	0.011	0.7%
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* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	GSLDT-2	General Service Large Demand - Time of Use (2000 kW +)				
2		Customer Charge	$236.44	$238.17	$1.73	0.7%
3						
4		Demand Charge - On-Peak ($/kW)	$12.60	$12.69	$0.09	0.7%
5						
6		Base Energy Charge (¢ per kWh)				
7		On-Peak	2.434	2.452	0.018	0.7%
8		Off-Peak	1.228	1.237	0.009	0.7%
9						
10						
11	CS-2	Curtailable Service (2000 kW +)				
12		Customer Charge	$262.71	$264.63	$1.92	0.7%
13						
14		Demand Charge ($/kW)	$12.60	$12.69	$0.09	0.7%
15						
16		Base Energy Charge (¢ per kWh)	1.568	1.579	0.011	0.7%
17						
18		Monthly Credit (per kW)	($2.04)	($2.05)	($0.01)	0.5%
19						
20		Charges for Non-Compliance of Curtailment Demand				
21		Rebilling for last 36 months (per kW)	$2.04	$2.05	$0.01	0.5%
22		Penalty Charge-current month (per kW)	$4.37	$4.40	$0.03	0.7%
23		Early Termination Penalty charge (per kW)	$1.29	$1.30	$0.01	0.8%
24						
25	CST-2	Curtailable Service -Time of Use (2000 kW +)				
26		Customer Charge	$262.71	$264.63	$1.92	0.7%
27						
28		Demand Charge - On-Peak ($/kW)	$12.60	$12.69	$0.09	0.7%
29						
30		Base Energy Charge (¢ per kWh)				
31		On-Peak	2.434	2.452	0.018	0.7%
32		Off-Peak	1.228	1.237	0.009	0.7%
33						
34		Monthly Credit (per kW)	($2.04)	($2.05)	($0.01)	0.5%
35						
36		Charges for Non-Compliance of Curtailment Demand				
37		Rebilling for last 36 months (per kW)	$2.04	$2.05	$0.01	0.5%
38		Penalty Charge-current month (per kW)	$4.37	$4.40	$0.03	0.7%
39		Early Termination Penalty charge (per kW)	$1.29	$1.30	$0.01	0.8%
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42						

* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	GSLD-3	General Service Large Demand (2000 kW +)				
2		Customer Charge	$2,099.40	$2,114.77	$15.37	0.7%
3						
4		Demand Charge ($/kW)	$9.77	$9.84	$0.07	0.7%
5						
6		Base Energy Charge (¢ per kWh)	1.127	1.135	0.008	0.7%
7						
8						
9	GSLDT-3	General Service Large Demand - Time of Use (2000 kW +)				
10		Customer Charge	$2,099.40	$2,114.77	$15.37	0.7%
11						
12		Demand Charge - On-Peak ($/kW)	$9.77	$9.84	$0.07	0.7%
13						
14		Base Energy Charge (¢ per kWh)				
15		On-Peak	1.287	1.296	0.009	0.7%
16		Off-Peak	1.070	1.078	0.008	0.7%
17						
18						
19	CS-3	Curtailable Service (2000 kW +)				
20		Customer Charge	$2,125.65	$2,141.21	$15.56	0.7%
21						
22		Demand Charge ($/kW)	$9.77	$9.84	$0.07	0.7%
23						
24		Base Energy Charge (¢ per kWh)	1.127	1.135	0.008	0.7%
25						
26		Monthly Credit (per kW)	($2.04)	($2.05)	($0.01)	0.5%
27						
28		Charges for Non-Compliance of Curtailment Demand				
29		Rebilling for last 36 months (per kW)	$2.04	$2.05	$0.01	0.5%
30		Penalty Charge-current month (per kW)	$4.37	$4.40	$0.03	0.7%
31		Early Termination Penalty charge (per kW)	$1.29	$1.30	$0.01	0.8%
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* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CST-3	Curtailable Service -Time of Use (2000 kW +)				
2		Customer Charge	$2,125.65	$2,141.21	$15.56	0.7%
3						
4		Demand Charge - On-Peak ($/kW)	$9.77	$9.84	$0.07	0.7%
5						
6		Base Energy Charge (¢ per kWh)				
7		On-Peak	1.287	1.296	0.009	0.7%
8		Off-Peak	1.070	1.078	0.008	0.7%
9						
10		Monthly Credit (per kW)	($2.04)	($2.05)	($0.01)	0.5%
11						
12		Charges for Non-Compliance of Curtailment Demand				
13		Rebilling for last 36 months (per kW)	$2.04	$2.05	$0.01	0.5%
14		Penalty Charge-current month (per kW)	$4.37	$4.40	$0.03	0.7%
15		Early Termination Penalty charge (per kW)	$1.29	$1.30	$0.01	0.8%
16						
17	OS-2	Sports Field Service [Schedule closed to new customers]				
18		Customer Charge	$131.89	$132.86	$0.97	0.7%
19						
20		Base Energy Charge (¢ per kWh)	8.299	8.360	0.061	0.7%
21						
22						
23	MET	Metropolitan Transit Service				
24		Customer Charge	$631.46	$636.08	$4.62	0.7%
25						
26		Base Demand Charge ($/kW)	$13.36	$13.46	$0.10	0.7%
27						
28		Base Energy Charge (¢ per kWh)	1.783	1.796	0.013	0.7%
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* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CILC-1	Commercial/Industrial Load Control Program [Schedule closed to new customers]				
2		Customer Charge				
3		(G) 200-499kW	$157.56	$158.71	$1.15	0.7%
4		(D) above 500kW	$262.24	$264.16	$1.92	0.7%
5		(T) transmission	$2,325.76	$2,342.78	$17.02	0.7%
6						
7		Base Demand Charge ($/kW)				
8		per kW of Max Demand All kW:				
9		(G) 200-499kW	$4.20	$4.23	$0.03	0.7%
10		(D) above 500kW	$4.41	$4.44	$0.03	0.7%
11		(T) transmission	None	None	None	N/A
12						
13						
14		per kW of Load Control On-Peak:				
15		(G) 200-499kW	$2.76	$2.78	$0.02	0.7%
16		per kW of Load Control On-Peak:				
17		(D) above 500kW	$3.15	$3.17	$0.02	0.6%
18		(T) transmission	$3.35	$3.37	$0.02	0.6%
19						
20						
21						
22		Per kW of Firm On-Peak Demand				
23		(G) 200-499kW	$10.50	$10.58	$0.08	0.8%
24		(D) above 500kW	$11.43	$11.51	$0.08	0.7%
25		(T) transmission	$12.22	$12.31	$0.09	0.7%
26						
27		Base Energy Charge (¢ per kWh)				
28		On-Peak				
29		(G) 200-499kW	1.565	1.576	0.011	0.7%
30		(D) above 500kW	1.053	1.061	0.008	0.8%
31		(T) transmission	0.977	0.984	0.007	0.7%
32		Off-Peak				
33		(G) 200-499kW	1.565	1.576	0.011	0.7%
34		(D) above 500kW	1.053	1.061	0.008	0.8%
35		(T) transmission	0.977	0.984	0.007	0.7%
36						
37		Excess "Firm Demand" or Termination Charge				
38		¤ Up to prior 60 months of service	Difference between Firm and			
39			Load-Control On-Peak Demand Charge			
40						
41		¤ Penalty Charge per kW for each month of rebilling	$1.13	$1.14	$0.01	0.9%
42						

* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CDR		Commercial/Industrial Demand Reduction Rider				
2			Monthly Rate				
3			Customer Charge	Otherwise Applicable Rate			
4			Demand Charge	Otherwise Applicable Rate			
5			Energy Charge	Otherwise Applicable Rate			
6							
7			Monthly Administrative Adder				
8			GSD-1	$131.56	$132.52	$0.96	0.7%
9			GSDT-1	$131.56	$132.52	$0.96	0.7%
10			GSLD-1, GSLDT-1	$184.04	$185.39	$1.35	0.7%
11			GSLD-2, GSLDT-2	$78.81	$79.39	$0.58	0.7%
12			GSLD-3, GSLDT-3	$236.18	$237.91	$1.73	0.7%
13			HLFT	Applicable General Service Level Rate			
14			SDTR	Applicable General Service Level Rate			
15							
16			Utility Controlled Demand Credit $/kW	($8.65)	($8.71)	($0.06)	0.7%
17							
18			Excess "Firm Demand"	$8.65	$8.71	$0.06	0.7%
19			¤ Up to prior 60 months of service				
20							
21			¤ Penalty Charge per kW for	$1.13	$1.14	$0.01	0.9%
22			each month of rebilling				
23							
24	SL-1		Street Lighting				
25			Charges for FPL-Owned Units				
26			Fixture				
27			Sodium Vapor 6,300 lu 70 watts	$4.11	$4.14	$0.03	0.7%
28			Sodium Vapor 9,500 lu 100 watts	$4.18	$4.21	$0.03	0.7%
29			Sodium Vapor 16,000 lu 150 watts	$4.31	$4.34	$0.03	0.7%
30			Sodium Vapor 22,000 lu 200 watts	$6.53	$6.58	$0.05	0.8%
31			Sodium Vapor 50,000 lu 400 watts	$6.59	$6.64	$0.05	0.8%
32		**	Sodium Vapor 27,500 lu 250 watts	$6.94	$6.99	$0.05	0.7%
33		**	Sodium Vapor 140,000 lu 1,000 watts	$10.46	$10.54	$0.08	0.8%
34		**	Mercury Vapor 6,000 lu 140 watts	$3.25	$3.27	$0.02	0.6%
35		**	Mercury Vapor 8,600 lu 175 watts	$3.31	$3.33	$0.02	0.6%
36		**	Mercury Vapor 11,500 lu 250 watts	$5.50	$5.54	$0.04	0.7%
37		**	Mercury Vapor 21,500 lu 400 watts	$5.47	$5.51	$0.04	0.7%
38							
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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE		(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SL-1		Street Lighting (continued))					
2			Maintenance					
3			Sodium Vapor 6,300 lu 70 watts		$1.97	$1.98	$0.01	0.5%
4			Sodium Vapor 9,500 lu 100 watts		$1.98	$1.99	$0.01	0.5%
5			Sodium Vapor 16,000 lu 150 watts		$2.01	$2.02	$0.01	0.5%
6			Sodium Vapor 22,000 lu 200 watts		$2.55	$2.57	$0.02	0.8%
7			Sodium Vapor 50,000 lu 400 watts		$2.56	$2.58	$0.02	0.8%
8		**	Sodium Vapor 27,500 lu 250 watts		$2.77	$2.79	$0.02	0.7%
9		**	Sodium Vapor 140,000 lu 1,000 watts		$4.97	$5.01	$0.04	0.8%
10		**	Mercury Vapor 6,000 lu 140 watts		$1.76	$1.77	$0.01	0.6%
11		**	Mercury Vapor 8,600 lu 175 watts		$1.76	$1.77	$0.01	0.6%
12		**	Mercury Vapor 11,500 lu 250 watts		$2.53	$2.55	$0.02	0.8%
13		**	Mercury Vapor 21,500 lu 400 watts		$2.49	$2.51	$0.02	0.8%
14								
15			Energy Non-Fuel	kWh				
16			Sodium Vapor 6,300 lu 70 watts	29	$0.88	$0.89	$0.01	1.1%
17			Sodium Vapor 9,500 lu 100 watts	41	$1.25	$1.26	$0.01	0.8%
18			Sodium Vapor 16,000 lu 150 watts	60	$1.82	$1.84	$0.02	1.1%
19			Sodium Vapor 22,000 lu 200 watts	88	$2.68	$2.70	$0.02	0.7%
20			Sodium Vapor 50,000 lu 400 watts	168	$5.11	$5.15	$0.04	0.8%
21		**	Sodium Vapor 27,500 lu 250 watts	116	$3.53	$3.55	$0.02	0.6%
22		**	Sodium Vapor 140,000 lu 1,000 watts	411	$12.50	$12.59	$0.09	0.7%
23		**	Mercury Vapor 6,000 lu 140 watts	62	$1.89	$1.90	$0.01	0.5%
24		**	Mercury Vapor 8,600 lu 175 watts	77	$2.34	$2.36	$0.02	0.9%
25		**	Mercury Vapor 11,500 lu 250 watts	104	$3.16	$3.19	$0.03	0.9%
26		**	Mercury Vapor 21,500 lu 400 watts	160	$4.87	$4.90	$0.03	0.6%
27								
28								
29			Note: The proposed monthly Non-Fuel Energy charge is calculated by multiplying the kWh rating for each fixture by the proposed					
30			Non-Fuel Energy Rate. This avoids rounding issues caused by separating the increases into the various components.					
31			**Note: These units are closed to new Company installations.					
32								
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* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE		(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SL-1		Street Lighting (continued))					
2			Charge for Customer-Owned Units					
3			Relamping and Energy					
4			Sodium Vapor 6,300 lu 70 watts		$2.86	$2.88	$0.02	0.7%
5			Sodium Vapor 9,500 lu 100 watts		$3.24	$3.26	$0.02	0.6%
6			Sodium Vapor 16,000 lu 150 watts		$3.84	$3.87	$0.03	0.8%
7			Sodium Vapor 22,000 lu 200 watts		$5.20	$5.24	$0.04	0.8%
8			Sodium Vapor 50,000 lu 400 watts		$7.64	$7.70	$0.06	0.8%
10		**	Sodium Vapor 27,500 lu 250 watts		$6.27	$6.31	$0.04	0.6%
11		**	Sodium Vapor 140,000 lu 1,000 watts		$17.51	$17.64	$0.13	0.7%
12		**	Mercury Vapor 6,000 lu 140 watts		$3.66	$3.68	$0.02	0.5%
13		**	Mercury Vapor 8,600 lu 175 watts		$4.11	$4.14	$0.03	0.7%
14		**	Mercury Vapor 11,500 lu 250 watts		$5.71	$5.76	$0.05	0.9%
15		**	Mercury Vapor 21,500 lu 400 watts		$7.37	$7.42	$0.05	0.7%
18								
19			Energy Only	kWh				
20			Sodium Vapor 6,300 lu 70 watts	29	$0.88	$0.89	$0.01	1.1%
21			Sodium Vapor 9,500 lu 100 watts	41	$1.25	$1.26	$0.01	0.8%
22			Sodium Vapor 16,000 lu 150 watts	60	$1.82	$1.84	$0.02	1.1%
23			Sodium Vapor 22,000 lu 200 watts	88	$2.68	$2.70	$0.02	0.7%
24			Sodium Vapor 50,000 lu 400 watts	168	$5.11	$5.15	$0.04	0.8%
26		**	Sodium Vapor 27,500 lu 250 watts	116	$3.53	$3.55	$0.02	0.6%
27		**	Sodium Vapor 140,000 lu 1,000 watts	411	$12.50	$12.59	$0.09	0.7%
28		**	Mercury Vapor 6,000 lu 140 watts	62	$1.89	$1.90	$0.01	0.5%
29		**	Mercury Vapor 8,600 lu 175 watts	77	$2.34	$2.36	$0.02	0.9%
30		**	Mercury Vapor 11,500 lu 250 watts	104	$3.16	$3.19	$0.03	0.9%
31		**	Mercury Vapor 21,500 lu 400 watts	160	$4.87	$4.90	$0.03	0.6%
34								
35			Non-Fuel Energy (¢ per kWh)		3.041	3.063	0.022	0.7%
36								
37								
38			Note: The monthly Relamp and Energy charge is calculated by adding the Relamp increase to the Energy-only increase avoiding rounding issues.					
39			**Note: These units are closed to new Company installations.					
40								
41								
42								

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SL-1	Street Lighting (continued))					
2		Other Charges					
3		Wood Pole		$5.20	$5.24	$0.04	0.8%
4		Concrete Pole / Steel Pole		$7.11	$7.16	$0.05	0.7%
5		Fiberglass Pole		$8.42	$8.48	$0.06	0.7%
6		Underground conductors not under paving (¢ per foot)		4.024	4.053	0.029	0.7%
7		Underground conductors under paving (¢ per foot)		9.831	9.903	0.072	0.7%
8							
9		Willful Damage					
10		Cost for Shield upon second occurrence		$280.00	$280.00	$0.00	0.0%
11							
12	SL-1M	Street Lighting					
13							
14		Customer Charge/Minimum		$14.78	$14.89	$0.11	0.7%
15		Base Energy Charge (¢ per kWh)		2.985	3.007	0.022	0.7%
16							
17							
18							
19	PL-1	Premium Lighting					
20		Present Value Revenue Requirement					
21		Multiplier		1.196	1.1961	0.000	0.0%
22							
23		Monthly Rate					
24		Facilities (Percentage of total work order cost)					
25		10 Year Payment Option		1.364%	1.364%	0.000	0.0%
26		20 Year Payment Option		0.926%	0.926%	0.000	0.0%
27							
28		Maintenance		FPL's estimated cost of maintaining facilities			
29							
30							
31		Termination Factors					
32		10 Year Payment Option					
33			1	1.1961	1.1961	0.000	0.0%
34			2	1.0324	1.0324	0.000	0.0%
35			3	0.9489	0.9489	0.000	0.0%
36			4	0.8590	0.8590	0.000	0.0%
37			5	0.7621	0.7621	0.000	0.0%
38			6	0.6576	0.6576	0.000	0.0%
39							
40							
41							
42							

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	PL-1	Premium Lighting (continued)					
2			7	0.5450	0.5450	0.000	0.0%
3			8	0.4237	0.4237	0.000	0.0%
4			9	0.2929	0.2929	0.000	0.0%
5			10	0.1519	0.1519	0.000	0.0%
6			>10	0.0000	0.0000	0.000	
7							
8		20 Year Payment Option					
9			1	1.1961	1.1961	0.000	0.0%
10			2	1.0850	1.0850	0.000	0.0%
11			3	1.0582	1.0582	0.000	0.0%
12			4	1.0293	1.0293	0.000	0.0%
13			5	0.9982	0.9982	0.000	0.0%
14			6	0.9646	0.9646	0.000	0.0%
15			7	0.9285	0.9285	0.000	0.0%
16			8	0.8895	0.8895	0.000	0.0%
17			9	0.8475	0.8475	0.000	0.0%
18			10	0.8023	0.8023	0.000	0.0%
19			11	0.7535	0.7535	0.000	0.0%
20			12	0.7009	0.7009	0.000	0.0%
21			13	0.6443	0.6443	0.000	0.0%
22			14	0.5832	0.5832	0.000	0.0%
23			15	0.5174	0.5174	0.000	0.0%
24			16	0.4465	0.4465	0.000	0.0%
25			17	0.3700	0.3700	0.000	0.0%
26			18	0.2876	0.2876	0.000	0.0%
27			19	0.1988	0.1988	0.000	0.0%
28			20	0.1031	0.1031	0.000	0.0%
29			>20	0.0000	0.0000	0.000	
30							
31		Non-Fuel Energy (¢ per kWh)		3.041	3.063	0.022	0.7%
32							
33		Willful Damage					
34		All occurrences after initial repair		Cost for repair or replacement			
35							
36	RL-1	Recreational Lighting [Schedule closed to new customers]					
37							
38		Non-Fuel Energy (¢ per kWh)		Otherwise applicable General			
39				Service Rate			
40							
41		Maintenance		FPL's estimated cost of maintaining facilities			
42							

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE		(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	OL-1		Outdoor Lighting					
2			Charges for FPL-Owned Units					
3			Fixture					
4			Sodium Vapor 6,300 lu 70 watts		$5.34	$5.38	$0.04	0.7%
5			Sodium Vapor 9,500 lu 100 watts		$5.45	$5.49	$0.04	0.7%
6			Sodium Vapor 16,000 lu 150 watts		$5.64	$5.68	$0.04	0.7%
7			Sodium Vapor 22,000 lu 200 watts		$8.20	$8.26	$0.06	0.7%
8			Sodium Vapor 50,000 lu 400 watts		$8.75	$8.81	$0.06	0.7%
9		**	Sodium Vapor 12,000 lu 150 watts		$5.64	$5.68	$0.04	0.7%
10		**	Mercury Vapor 6,000 lu 140 watts		$4.10	$4.13	$0.03	0.7%
11		**	Mercury Vapor 8,600 lu 175 watts		$4.12	$4.15	$0.03	0.7%
12		**	Mercury Vapor 21,500 lu 400 watts		$6.75	$6.80	$0.05	0.7%
13								
14			Maintenance					
15			Sodium Vapor 6,300 lu 70 watts		$2.02	$2.03	$0.01	0.5%
16			Sodium Vapor 9,500 lu 100 watts		$2.02	$2.03	$0.01	0.5%
17			Sodium Vapor 16,000 lu 150 watts		$2.05	$2.07	$0.02	1.0%
18			Sodium Vapor 22,000 lu 200 watts		$2.63	$2.65	$0.02	0.8%
19			Sodium Vapor 50,000 lu 400 watts		$2.59	$2.61	$0.02	0.8%
20		**	Sodium Vapor 12,000 lu 150 watts		$2.05	$2.07	$0.02	1.0%
21		**	Mercury Vapor 6,000 lu 140 watts		$1.80	$1.81	$0.01	0.6%
22		**	Mercury Vapor 8,600 lu 175 watts		$1.80	$1.81	$0.01	0.6%
23		**	Mercury Vapor 21,500 lu 400 watts		$2.53	$2.55	$0.02	0.8%
24								
25			Energy Non-Fuel	kWh				
26			Sodium Vapor 6,300 lu 70 watts	29	$0.94	$0.95	$0.01	1.1%
27			Sodium Vapor 9,500 lu 100 watts	41	$1.33	$1.34	$0.01	0.8%
28			Sodium Vapor 16,000 lu 150 watts	60	$1.95	$1.96	$0.01	0.5%
29			Sodium Vapor 22,000 lu 200 watts	88	$2.86	$2.88	$0.02	0.7%
30			Sodium Vapor 50,000 lu 400 watts	168	$5.45	$5.49	$0.04	0.7%
31		**	Sodium Vapor 12,000 lu 150 watts	60	$1.95	$1.96	$0.01	0.5%
32		**	Mercury Vapor 6,000 lu 140 watts	62	$2.01	$2.03	$0.02	1.0%
33		**	Mercury Vapor 8,600 lu 175 watts	77	$2.50	$2.52	$0.02	0.8%
34		**	Mercury Vapor 21,500 lu 400 watts	160	$5.19	$5.23	$0.04	0.8%
35								
36								
37								
38								
39								
40								
41								
42	Note: The monthly Relamp and Energy charge is calculated by adding the Relamp increase to the Energy-only increase avoiding rounding issues.							
	**Note: These units are closed to new Company installations.							

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE			(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	OL-1		Outdoor Lighting (continued)						
2			Charges for Customer Owned Units						
3			Total Charge-Relamping & Energy						
4			Sodium Vapor 6,300 lu 70 watts			$2.91	$2.93	$0.02	0.7%
5			Sodium Vapor 9,500 lu 100 watts			$3.30	$3.32	$0.02	0.6%
6			Sodium Vapor 16,000 lu 150 watts			$3.95	$3.97	$0.02	0.5%
7			Sodium Vapor 22,000 lu 200 watts			$5.43	$5.47	$0.04	0.7%
8			Sodium Vapor 50,000 lu 400 watts			$7.97	$8.03	$0.06	0.8%
9		**	Sodium Vapor 12,000 lu 150 watts			$4.23	$4.26	$0.03	0.7%
10		**	Mercury Vapor 6,000 lu 140 watts			$3.77	$3.80	$0.03	0.8%
11		**	Mercury Vapor 8,600 lu 175 watts			$4.26	$4.29	$0.03	0.7%
12		**	Mercury Vapor 21,500 lu 400 watts			$7.66	$7.72	$0.06	0.8%
13									
14			Energy Only	kWh					
15			Sodium Vapor 6,300 lu 70 watts		29	$0.94	$0.95	$0.01	1.1%
16			Sodium Vapor 9,500 lu 100 watts		41	$1.33	$1.34	$0.01	0.8%
17			Sodium Vapor 16,000 lu 150 watts		60	$1.95	$1.96	$0.01	0.5%
18			Sodium Vapor 22,000 lu 200 watts		88	$2.86	$2.88	$0.02	0.7%
19			Sodium Vapor 50,000 lu 400 watts		168	$5.45	$5.49	$0.04	0.7%
20		**	Sodium Vapor 12,000 lu 150 watts		60	$1.95	$1.96	$0.01	0.5%
21		**	Mercury Vapor 6,000 lu 140 watts		62	$2.01	$2.03	$0.02	1.0%
22		**	Mercury Vapor 8,600 lu 175 watts		77	$2.50	$2.52	$0.02	0.8%
23		**	Mercury Vapor 21,500 lu 400 watts		160	$5.19	$5.23	$0.04	0.8%
24									
25			Non-Fuel Energy (¢ per kWh)			3.246	3.270	0.024	0.7%
26									
27			Other Charges						
28			Wood Pole			$11.75	$11.84	$0.09	0.8%
29			Concrete Pole / Steel Pole			$15.88	$16.00	$0.12	0.8%
30			Fiberglass Pole			$18.66	$18.80	$0.14	0.8%
31			Underground conductors excluding						
32			Trenching per foot			$0.090	$0.091	$0.001	1.1%
33			Down-guy, Anchor and Protector			$10.69	$10.77	$0.08	0.7%
34									
35	SL-2		Traffic Signal Service						
36			Minimum Charge at each point			$3.41	$3.43	$0.02	0.6%
37			Base Energy Charge (¢ per kWh)			4.979	5.015	0.036	0.7%
38									
39	SL-2M		Traffic Signal Service						
40			Customer Charge/Minimum			$6.33	$6.38	$0.05	0.8%
41			Base Energy Charge (¢ per kWh)			4.838	4.873	0.035	0.7%
42									

**Note: These units are closed to new Company installations.

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SST-1	Standby and Supplemental Service				
2		Customer Charge				
3		SST-1(D1)	$131.78	$132.74	$0.96	0.7%
4		SST-1(D2)	$131.78	$132.74	$0.96	0.7%
5		SST-1(D3)	$448.04	$451.32	$3.28	0.7%
6		SST-1(T)	$1,899.93	$1,913.84	$13.91	0.7%
7						
8		Distribution Demand $/kW Contract Standby Demand				
9		SST-1(D1)	$3.16	$3.18	$0.02	0.6%
10		SST-1(D2)	$3.16	$3.18	$0.02	0.6%
11		SST-1(D3)	$3.16	$3.18	$0.02	0.6%
12		SST-1(T)	N/A	N/A	N/A	N/A
13						
14		Reservation Demand $/kW				
15		SST-1(D1)	$1.56	$1.57	$0.01	0.6%
16		SST-1(D2)	$1.56	$1.57	$0.01	0.6%
17		SST-1(D3)	$1.56	$1.57	$0.01	0.6%
18		SST-1(T)	$1.42	$1.43	$0.01	0.7%
19						
20		Daily Demand (On-Peak) $/kW				
21		SST-1(D1)	$0.75	$0.76	$0.01	1.3%
22		SST-1(D2)	$0.75	$0.76	$0.01	1.3%
23		SST-1(D3)	$0.75	$0.76	$0.01	1.3%
24		SST-1(T)	$0.45	$0.45	$0.00	0.0%
25						
26		Supplemental Service				
27		Demand	Otherwise Applicable Rate			
28		Energy	Otherwise Applicable Rate			
29						
30		Non-Fuel Energy - On-Peak (¢ per kWh)				
31		SST-1(D1)	0.751	0.756	0.005	0.7%
32		SST-1(D2)	0.751	0.756	0.005	0.7%
33		SST-1(D3)	0.751	0.756	0.005	0.7%
34		SST-1(T)	0.748	0.753	0.005	0.7%
35		Non-Fuel Energy - Off-Peak (¢ per kWh)				
36		SST-1(D1)	0.751	0.756	0.005	0.7%
37		SST-1(D2)	0.751	0.756	0.005	0.7%
38		SST-1(D3)	0.751	0.756	0.005	0.7%
39		SST-1(T)	0.748	0.753	0.005	0.7%
40						
41						
42						

* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	ISST-1	Interruptible Standby and Supplemental Service				
2		Customer Charge				
3		Distribution	$448.04	$451.32	$3.28	0.7%
4		Transmission	$1,899.93	$1,913.84	$13.91	0.7%
5						
6		Distribution Demand				
7		Distribution	$3.16	$3.18	$0.02	0.6%
8		Transmission	N/A	N/A	N/A	N/A
9						
10		Reservation Demand-Interruptible				
11		Distribution	$0.27	$0.27	$0.00	0.0%
12		Transmission	$0.31	$0.31	$0.00	0.0%
13						
14		Reservation Demand-Firm				
15		Distribution	$1.56	$1.57	$0.01	0.6%
16		Transmission	$1.42	$1.43	$0.01	0.7%
17						
18		Supplemental Service				
19		Demand	Otherwise Applicable Rate			
20		Energy	Otherwise Applicable Rate			
21						
22		Daily Demand (On-Peak) Firm Standby				
23		Distribution	$0.75	$0.76	$0.01	1.3%
24		Transmission	$0.45	$0.45	$0.00	0.0%
25						
26		Daily Demand (On-Peak) Interruptible Standby				
27		Distribution	$0.13	$0.13	$0.00	0.0%
28		Transmission	$0.12	$0.12	$0.00	0.0%
29						
30		Non-Fuel Energy - On-Peak (¢ per kWh)				
31		Distribution	0.751	0.756	0.005	0.7%
32		Transmission	0.748	0.753	0.005	0.7%
33		Non-Fuel Energy - Off-Peak (¢ per kWh)				
34		Distribution	0.751	0.756	0.005	0.7%
35		Transmission	0.748	0.753	0.005	0.7%
36						
37		Excess "Firm Standby Demand"				
38		¤ Up to prior 60 months of service	Difference between reservation charge for			
39			firm and interruptible standby demand			
40			times excess demand			
41						
42		¤ Penalty Charge per kW for each month of rebilling	$1.13	$1.14	$0.01	0.9%

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	TR	Transformation Rider				
2		Transformer Credit				
3		(per kW of Billing Demand)	($0.15)	($0.15)	$0.00	0.0%
4						
5						
6	GSCU-1	General Service constant Usage				
7		Customer Charge:	$14.75	$14.86	$0.11	0.7%
8						
9		Non-Fuel Energy Charges:				
10		Base Energy Charge*	3.703	3.730	0.027	0.7%
11		* The fuel and non-fuel energy charges will be assessed on the Constant Usage kWh				
12						
13						
14	HLFT-1	High Load Factor - Time of Use				
15		Customer Charge:				
16		21 - 499 kW:	$26.31	$26.50	$0.19	0.7%
17		500 - 1,999 kW	$78.87	$79.45	$0.58	0.7%
18		2,000 kW or greater	$236.44	$238.17	$1.73	0.7%
19						
20		Demand Charges:				
21		On-peak Demand Charge:				
22		21 - 499 kW:	$11.67	$11.76	$0.09	0.8%
23		500 - 1,999 kW	$12.72	$12.81	$0.09	0.7%
24		2,000 kW or greater	$12.81	$12.90	$0.09	0.7%
25						
26		Maximum Demand Charge:				
27		21 - 499 kW:	$2.42	$2.44	$0.02	0.8%
28		500 - 1,999 kW	$2.73	$2.75	$0.02	0.7%
29		2,000 kW or greater	$2.72	$2.74	$0.02	0.7%
30						
31		Non-Fuel Energy Charges: (¢ per kWh)				
32		On-Peak Period				
33		21 - 499 kW:	1.908	1.922	0.014	0.7%
34		500 - 1,999 kW	1.126	1.134	0.008	0.7%
35		2,000 kW or greater	1.001	1.008	0.007	0.7%
36						
37						
38						
39						
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	HLFT-1	High Load Factor - Time of Use (continued)				
2		Off-Peak Period				
3		21 - 499 kW:	1.190	1.199	0.009	0.8%
4		500 - 1,999 kW	1.076	1.084	0.008	0.7%
5		2,000 kW or greater	0.993	1.000	0.007	0.7%
6						
7						
8	SDTR	Seasonal Demand – Time of Use Rider				
9		Option A				
10		Customer Charge:				
11		21 - 499 kW:	$26.31	$26.50	$0.19	0.7%
12		500 - 1,999 kW	$78.87	$79.45	$0.58	0.7%
13		2,000 kW or greater	$236.44	$238.17	$1.73	0.7%
14						
15		Demand Charges:				
16		Seasonal On-peak Demand:				
17		21 - 499 kW:	$10.95	$11.03	$0.08	0.7%
18		500 - 1,999 kW	$12.51	$12.60	$0.09	0.7%
19		2,000 kW or greater	$13.10	$13.20	$0.10	0.8%
20						
21		Non-seasonal Demand Max Demand:				
22		21 - 499 kW:	$9.47	$9.54	$0.07	0.7%
23		500 - 1,999 kW	$11.88	$11.97	$0.09	0.8%
24		2,000 kW or greater	$12.37	$12.46	$0.09	0.7%
25						
26		Energy Charges (¢ per kWh):				
27		Seasonal On-peak Energy:				
28		21 - 499 kW:	8.771	8.835	0.064	0.7%
29		500 - 1,999 kW	6.200	6.245	0.045	0.7%
30		2,000 kW or greater	4.919	4.955	0.036	0.7%
31						
32		Seasonal Off-peak Energy:				
33		21 - 499 kW:	1.582	1.594	0.012	0.8%
34		500 - 1,999 kW	1.257	1.266	0.009	0.7%
35		2,000 kW or greater	1.228	1.237	0.009	0.7%
36						
37		Non-seasonal Energy				
38		21 - 499 kW:	2.206	2.222	0.016	0.7%
39		500 - 1,999 kW	1.742	1.755	0.013	0.7%
40		2,000 kW or greater	1.568	1.579	0.011	0.7%
41						
42						

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SDTR	Seasonal Demand – Time of Use Rider (continued)				
2		Option B				
3		Customer Charge:				
4		21 - 499 kW:	$26.31	$26.50	$0.19	0.7%
5		500 - 1,999 kW	$78.87	$79.45	$0.58	0.7%
6		2,000 kW or greater	$236.44	$238.17	$1.73	0.7%
7						
8		Demand Charges:				
9		Seasonal On-peak Demand:				
10		21 - 499 kW:	$10.95	$11.03	$0.08	0.7%
11		500 - 1,999 kW	$12.51	$12.60	$0.09	0.7%
12		2,000 kW or greater	$13.10	$13.20	$0.10	0.8%
13						
14		Non-seasonal On-peak Demand:				
15		21 - 499 kW:	$9.47	$9.54	$0.07	0.7%
16		500 - 1,999 kW	$11.88	$11.97	$0.09	0.8%
17		2,000 kW or greater	$12.37	$12.46	$0.09	0.7%
18						
19		Energy Charges (¢ per kWh):				
20		Seasonal On-peak Energy:				
21		21 - 499 kW:	8.771	8.835	0.064	0.7%
22		500 - 1,999 kW	6.200	6.245	0.045	0.7%
23		2,000 kW or greater	4.919	4.955	0.036	0.7%
24						
25		Seasonal Off-peak Energy:				
26		21 - 499 kW:	1.582	1.594	0.012	0.8%
27		500 - 1,999 kW	1.257	1.266	0.009	0.7%
28		2,000 kW or greater	1.228	1.237	0.009	0.7%
29						
30		Non-seasonal On-peak Energy:				
31		21 - 499 kW:	5.012	5.049	0.037	0.7%
32		500 - 1,999 kW	3.711	3.738	0.027	0.7%
33		2,000 kW or greater	3.386	3.411	0.025	0.7%
34						
35		Non-seasonal Off-peak Energy:				
36		21 - 499 kW:	1.582	1.594	0.012	0.8%
37		500 - 1,999 kW	1.257	1.266	0.009	0.7%
38		2,000 kW or greater	1.228	1.237	0.009	0.7%
39						
40						
41						
42						

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	NSMR	Non-Standard Meter Rate					
2							
3		Enrollment Fee					
4		GS-1		$89.00	$89.00	$0.00	0.0%
5		GSD-1		$89.00	$89.00	$0.00	0.0%
6		RS-1		$89.00	$89.00	$0.00	0.0%
7							
8		Monthly Surcharge					
9		GS-1		$13.00	$13.00	$0.00	0.0%
10		GSD-1		$13.00	$13.00	$0.00	0.0%
11		RS-1		$13.00	$13.00	$0.00	0.0%
12							
13							
14	LT-1	LED Lighting Pilot					
15		LED Fixtures					
16		Fixture Tier	Energy Tier				
17		1	A	$1.50	$1.50	$0.00	0.0%
18		1	B	$1.70	$1.70	$0.00	0.0%
19		1	C	$1.90	$1.90	$0.00	0.0%
20		1	D	$2.10	$2.10	$0.00	0.0%
21		1	E	$2.30	$2.30	$0.00	0.0%
22		1	F	$2.50	$2.50	$0.00	0.0%
23		1	G	$2.70	$2.70	$0.00	0.0%
24		1	H	$2.90	$2.90	$0.00	0.0%
25		1	I	$3.10	$3.10	$0.00	0.0%
26		1	J	$3.30	$3.30	$0.00	0.0%
27		1	K	$3.50	$3.50	$0.00	0.0%
28		1	L	$3.70	$3.70	$0.00	0.0%
29		1	M	$3.90	$3.90	$0.00	0.0%
30		1	N	$4.10	$4.10	$0.00	0.0%
31		1	O	$4.30	$4.30	$0.00	0.0%
32		1	P	$4.50	$4.50	$0.00	0.0%
33		1	Q	$4.70	$4.70	$0.00	0.0%
34		1	R	$4.90	$4.90	$0.00	0.0%
35		1	S	$5.10	$5.10	$0.00	0.0%
36		1	T	$5.30	$5.30	$0.00	0.0%
37		2	A	$4.50	$4.50	$0.00	0.0%
38		2	B	$4.70	$4.70	$0.00	0.0%
39		2	C	$4.90	$4.90	$0.00	0.0%
40		2	D	$5.10	$5.10	$0.00	0.0%
41		2	E	$5.30	$5.30	$0.00	0.0%
42		2	F	$5.50	$5.50	$0.00	0.0%

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	LT-1	LED Lighting Pilot (continued)					
2		2	G	$5.70	$5.70	$0.00	0.0%
3		2	H	$5.90	$5.90	$0.00	0.0%
4		2	I	$6.10	$6.10	$0.00	0.0%
5		2	J	$6.30	$6.30	$0.00	0.0%
6		2	K	$6.50	$6.50	$0.00	0.0%
7		2	L	$6.70	$6.70	$0.00	0.0%
8		2	M	$6.90	$6.90	$0.00	0.0%
9		2	N	$7.10	$7.10	$0.00	0.0%
10		2	O	$7.30	$7.30	$0.00	0.0%
11		2	P	$7.50	$7.50	$0.00	0.0%
12		2	Q	$7.70	$7.70	$0.00	0.0%
13		2	R	$7.90	$7.90	$0.00	0.0%
14		2	S	$8.10	$8.10	$0.00	0.0%
15		2	T	$8.30	$8.30	$0.00	0.0%
16		3	A	$7.50	$7.50	$0.00	0.0%
17		3	B	$7.70	$7.70	$0.00	0.0%
18		3	C	$7.90	$7.90	$0.00	0.0%
19		3	D	$8.10	$8.10	$0.00	0.0%
20		3	E	$8.30	$8.30	$0.00	0.0%
21		3	F	$8.50	$8.50	$0.00	0.0%
22		3	G	$8.70	$8.70	$0.00	0.0%
23		3	H	$8.90	$8.90	$0.00	0.0%
24		3	I	$9.10	$9.10	$0.00	0.0%
25		3	J	$9.30	$9.30	$0.00	0.0%
26		3	K	$9.50	$9.50	$0.00	0.0%
27		3	L	$9.70	$9.70	$0.00	0.0%
28		3	M	$9.90	$9.90	$0.00	0.0%
29		3	N	$10.10	$10.10	$0.00	0.0%
30		3	O	$10.30	$10.30	$0.00	0.0%
31		3	P	$10.50	$10.50	$0.00	0.0%
32		3	Q	$10.70	$10.70	$0.00	0.0%
33		3	R	$10.90	$10.90	$0.00	0.0%
34		3	S	$11.10	$11.10	$0.00	0.0%
35		3	T	$11.30	$11.30	$0.00	0.0%
36		4	A	$10.50	$10.50	$0.00	0.0%
37		4	B	$10.70	$10.70	$0.00	0.0%
38		4	C	$10.90	$10.90	$0.00	0.0%
39		4	D	$11.10	$11.10	$0.00	0.0%
40		4	E	$11.30	$11.30	$0.00	0.0%
41		4	F	$11.50	$11.50	$0.00	0.0%
42		4	G	$11.70	$11.70	$0.00	0.0%

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	LT-1	LED Lighting Pilot (continued)					
2		4	H	$11.90	$11.90	$0.00	0.0%
3		4	I	$12.10	$12.10	$0.00	0.0%
4		4	J	$12.30	$12.30	$0.00	0.0%
5		4	K	$12.50	$12.50	$0.00	0.0%
6		4	L	$12.70	$12.70	$0.00	0.0%
7		4	M	$12.90	$12.90	$0.00	0.0%
8		4	N	$13.10	$13.10	$0.00	0.0%
9		4	O	$13.30	$13.30	$0.00	0.0%
10		4	P	$13.50	$13.50	$0.00	0.0%
11		4	Q	$13.70	$13.70	$0.00	0.0%
12		4	R	$13.90	$13.90	$0.00	0.0%
13		4	S	$14.10	$14.10	$0.00	0.0%
14		4	T	$14.30	$14.30	$0.00	0.0%
15		5	A	$13.50	$13.50	$0.00	0.0%
16		5	B	$13.70	$13.70	$0.00	0.0%
17		5	C	$13.90	$13.90	$0.00	0.0%
18		5	D	$14.10	$14.10	$0.00	0.0%
19		5	E	$14.30	$14.30	$0.00	0.0%
20		5	F	$14.50	$14.50	$0.00	0.0%
21		5	G	$14.70	$14.70	$0.00	0.0%
22		5	H	$14.90	$14.90	$0.00	0.0%
23		5	I	$15.10	$15.10	$0.00	0.0%
24		5	J	$15.30	$15.30	$0.00	0.0%
25		5	K	$15.50	$15.50	$0.00	0.0%
26		5	L	$15.70	$15.70	$0.00	0.0%
27		5	M	$15.90	$15.90	$0.00	0.0%
28		5	N	$16.10	$16.10	$0.00	0.0%
29		5	O	$16.30	$16.30	$0.00	0.0%
30		5	P	$16.50	$16.50	$0.00	0.0%
31		5	Q	$16.70	$16.70	$0.00	0.0%
32		5	R	$16.90	$16.90	$0.00	0.0%
33		5	S	$17.10	$17.10	$0.00	0.0%
34		5	T	$17.30	$17.30	$0.00	0.0%
35		6	A	$16.50	$16.50	$0.00	0.0%
36		6	B	$16.70	$16.70	$0.00	0.0%
37		6	C	$16.90	$16.90	$0.00	0.0%
38		6	D	$17.10	$17.10	$0.00	0.0%
39		6	E	$17.30	$17.30	$0.00	0.0%
40		6	F	$17.50	$17.50	$0.00	0.0%
41		6	G	$17.70	$17.70	$0.00	0.0%
42		6	H	$17.90	$17.90	$0.00	0.0%

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
	LT-1	LED Lighting Pilot (continued)					
1		6	I	$18.10	$18.10	$0.00	0.0%
2		6	J	$18.30	$18.30	$0.00	0.0%
3		6	K	$18.50	$18.50	$0.00	0.0%
4		6	L	$18.70	$18.70	$0.00	0.0%
5		6	M	$18.90	$18.90	$0.00	0.0%
6		6	N	$19.10	$19.10	$0.00	0.0%
7		6	O	$19.30	$19.30	$0.00	0.0%
8		6	P	$19.50	$19.50	$0.00	0.0%
9		6	Q	$19.70	$19.70	$0.00	0.0%
10		6	R	$19.90	$19.90	$0.00	0.0%
11		6	S	$20.10	$20.10	$0.00	0.0%
12		6	T	$20.30	$20.30	$0.00	0.0%
13		7	A	$19.50	$19.50	$0.00	0.0%
14		7	B	$19.70	$19.70	$0.00	0.0%
15		7	C	$19.90	$19.90	$0.00	0.0%
16		7	D	$20.10	$20.10	$0.00	0.0%
17		7	E	$20.30	$20.30	$0.00	0.0%
18		7	F	$20.50	$20.50	$0.00	0.0%
19		7	G	$20.70	$20.70	$0.00	0.0%
20		7	H	$20.90	$20.90	$0.00	0.0%
21		7	I	$21.10	$21.10	$0.00	0.0%
22		7	J	$21.30	$21.30	$0.00	0.0%
23		7	K	$21.50	$21.50	$0.00	0.0%
24		7	L	$21.70	$21.70	$0.00	0.0%
25		7	M	$21.90	$21.90	$0.00	0.0%
26		7	N	$22.10	$22.10	$0.00	0.0%
27		7	O	$22.30	$22.30	$0.00	0.0%
28		7	P	$22.50	$22.50	$0.00	0.0%
29		7	Q	$22.70	$22.70	$0.00	0.0%
30		7	R	$22.90	$22.90	$0.00	0.0%
31		7	S	$23.10	$23.10	$0.00	0.0%
32		7	T	$23.30	$23.30	$0.00	0.0%
33		8	A	$22.50	$22.50	$0.00	0.0%
34		8	B	$22.70	$22.70	$0.00	0.0%
35		8	C	$22.90	$22.90	$0.00	0.0%
36		8	D	$23.10	$23.10	$0.00	0.0%
37		8	E	$23.30	$23.30	$0.00	0.0%
38		8	F	$23.50	$23.50	$0.00	0.0%
39		8	G	$23.70	$23.70	$0.00	0.0%
40		8	H	$23.90	$23.90	$0.00	0.0%
41		8	I	$24.10	$24.10	$0.00	0.0%
42		8	J	$24.30	$24.30	$0.00	0.0%

* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
	LT-1	LED Lighting Pilot (continued)					
1		8	K	$24.50	$24.50	$0.00	0.0%
2		8	L	$24.70	$24.70	$0.00	0.0%
3		8	M	$24.90	$24.90	$0.00	0.0%
4		8	N	$25.10	$25.10	$0.00	0.0%
5		8	O	$25.30	$25.30	$0.00	0.0%
6		8	P	$25.50	$25.50	$0.00	0.0%
7		8	Q	$25.70	$25.70	$0.00	0.0%
8		8	R	$25.90	$25.90	$0.00	0.0%
9		8	S	$26.10	$26.10	$0.00	0.0%
10		8	T	$26.30	$26.30	$0.00	0.0%
11		9	A	$25.50	$25.50	$0.00	0.0%
12		9	B	$25.70	$25.70	$0.00	0.0%
13		9	C	$25.90	$25.90	$0.00	0.0%
14		9	D	$26.10	$26.10	$0.00	0.0%
15		9	E	$26.30	$26.30	$0.00	0.0%
16		9	F	$26.50	$26.50	$0.00	0.0%
17		9	G	$26.70	$26.70	$0.00	0.0%
18		9	H	$26.90	$26.90	$0.00	0.0%
19		9	I	$27.10	$27.10	$0.00	0.0%
20		9	J	$27.30	$27.30	$0.00	0.0%
21		9	K	$27.50	$27.50	$0.00	0.0%
22		9	L	$27.70	$27.70	$0.00	0.0%
23		9	M	$27.90	$27.90	$0.00	0.0%
24		9	N	$28.10	$28.10	$0.00	0.0%
25		9	O	$28.30	$28.30	$0.00	0.0%
26		9	P	$28.50	$28.50	$0.00	0.0%
27		9	Q	$28.70	$28.70	$0.00	0.0%
28		9	R	$28.90	$28.90	$0.00	0.0%
29		9	S	$29.10	$29.10	$0.00	0.0%
30		9	T	$29.30	$29.30	$0.00	0.0%
31		10	A	$28.50	$28.50	$0.00	0.0%
32		10	B	$28.70	$28.70	$0.00	0.0%
33		10	C	$28.90	$28.90	$0.00	0.0%
34		10	D	$29.10	$29.10	$0.00	0.0%
35		10	E	$29.30	$29.30	$0.00	0.0%
36		10	F	$29.50	$29.50	$0.00	0.0%
37		10	G	$29.70	$29.70	$0.00	0.0%
38		10	H	$29.90	$29.90	$0.00	0.0%
39		10	I	$30.10	$30.10	$0.00	0.0%
40		10	J	$30.30	$30.30	$0.00	0.0%
41		10	K	$30.50	$30.50	$0.00	0.0%
42		10	L	$30.70	$30.70	$0.00	0.0%

* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) JANUARY 1, 2020 PROPOSED RATE*	(4) MAY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
	LT-1	LED Lighting Pilot (continued)				
1		10 M	$30.90	$30.90	$0.00	0.0%
2		10 N	$31.10	$31.10	$0.00	0.0%
3		10 O	$31.30	$31.30	$0.00	0.0%
4		10 P	$31.50	$31.50	$0.00	0.0%
5		10 Q	$31.70	$31.70	$0.00	0.0%
6		10 R	$31.90	$31.90	$0.00	0.0%
7		10 S	$32.10	$32.10	$0.00	0.0%
8		10 T	$32.30	$32.30	$0.00	0.0%
9						
10						
11		Energy Tier Charges				
12		Energy Tier				
13		A	$0.00	$0.00	$0.00	0.0%
14		B	$0.20	$0.20	$0.00	0.0%
15		C	$0.40	$0.40	$0.00	0.0%
16		D	$0.60	$0.60	$0.00	0.0%
17		E	$0.80	$0.80	$0.00	0.0%
18		F	$1.00	$1.00	$0.00	0.0%
19		G	$1.20	$1.20	$0.00	0.0%
20		H	$1.40	$1.40	$0.00	0.0%
21		I	$1.60	$1.60	$0.00	0.0%
22		J	$1.80	$1.80	$0.00	0.0%
23		K	$2.00	$2.00	$0.00	0.0%
24		L	$2.20	$2.20	$0.00	0.0%
25		M	$2.40	$2.40	$0.00	0.0%
26		N	$2.60	$2.60	$0.00	0.0%
27		O	$2.80	$2.80	$0.00	0.0%
28		P	$3.00	$3.00	$0.00	0.0%
29		Q	$3.20	$3.20	$0.00	0.0%
30		R	$3.40	$3.40	$0.00	0.0%
31		S	$3.60	$3.60	$0.00	0.0%
32		T	$3.80	$3.80	$0.00	0.0%
33						
34		Non-Fuel Energy (¢ per kWh)	3.041	3.063	0.022	0.7%
35						
36						
37		Charges for Maintenance and Conversion Recovery:				
38		Maintenance per Fixture (FPL Owned Fixture and Pole)	$1.82	$1.83	$0.01	0.5%
39		Maintenance per Fixture for FPL Fixtures on Customer Pole	$1.27	$1.28	$0.01	0.8%
40		LED Conversion Recovery	$1.03	$1.04	$0.01	1.0%
41						
42		Charges for Other FPL-Owned Facilities:				
43		Wood pole used only for the street lighting system	$5.20	$5.24	$0.04	0.8%
44		Standard Concrete pole used only for the street lighting system	$7.11	$7.16	$0.05	0.7%
45		Round Fiberglass pole used only for the street lighting system	$8.42	$8.48	$0.06	0.7%
46		Decorative Tall Fiberglass pole used only for the street lighting system	$17.76	$17.89	$0.13	0.7%
47		Decorative Concrete pole used only for the street lighting system	$14.42	$14.53	$0.11	0.8%
48		Underground conductors (¢ per foot)	4.024	4.053	0.029	0.7%

* Refer to as filed Exhibit EJA-8 for proposed January 1, 2020 rates

FLORIDA POWER & LIGHT COMPANY
SOBRA FACTOR CALCULATION
REVISED 2017 SOBRA FACTOR

2017 SOBRA FACTOR TRUE-UP CALCULATION		**($Million)**	**Source**
(A)	Initial 2017 Project Jurisdictional Annualized Revenue Requirement *	$60.523	See Note
(B)	Revised 2017 Project Jurisdictional Annualized Revenue Requirement	$57.371	Exhibit LF-2 as Filed
(C)	Change in Jurisdictional Annualized Revenue Requirement	($3.152)	Exhibit LF-2 as Filed
(D)	Total Retail Base Revenues From the Sales of Electricity *	$6,458.109	See Note
(E)	Revised SoBRA Factor [(B) / (D)]	0.888%	
(F)	Inital SoBRA Factor **	0.937%	See Note

* As filed in TCC-1, Page 1 of 1; Docket No. 20170001-EI
** As filed in TCC-2, Page 1 of 2; Docket No. 20170001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 43
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: E. J. Anderson EJA-4

FLORIDA POWER & LIGHT COMPANY
2017 PROJECT REVENUE - SOBRA PROVISION FOR REFUND CALCULATION

	(1)	(2)	(3)	(4)	(5)
		ACTUALS		REVISED	
	UNBILLED	BILLED	UNBILLED + BILLED	UNBILLED + BILLED	
	SOBRA REV	SOBRA REV	SOBRA REV	SOBRA REV	REFUND
Jan-18	(32,060)	4,605,381	4,573,322	4,334,162	239,160
Feb-18	(135,229)	4,278,381	4,143,152	3,926,488	216,664
Mar-18	139,068	4,312,401	4,451,469	4,218,682	232,788
Apr-18	288,910	4,515,155	4,804,065	4,552,838	251,226
May-18	43,172	4,932,602	4,975,774	4,715,568	260,206
Jun-18	247,919	5,347,505	5,595,424	5,302,813	292,610
Jul-18	145,655	5,912,702	6,058,357	5,741,538	316,819
Aug-18	(3,296)	6,098,438	6,095,142	5,776,399	318,743
Sep-18	91,960	5,770,084	5,862,044	5,555,491	306,553
Oct-18	(218,868)	5,833,556	5,614,689	5,321,071	293,618
Nov-18	(378,132)	5,095,873	4,717,741	4,471,029	246,712
Dec-18	(60,903)	4,504,059	4,443,156	4,210,803	232,353
Jan-19	(199,906)	4,493,716	4,293,811	4,069,268	224,543
Feb-19	127,662	4,213,263	4,340,924	4,113,918	227,007
Mar-19	69,801	4,507,892	4,577,693	4,338,305	239,388
Apr-19	295,977	4,866,949	5,162,926	4,892,933	269,993
May-19	553,653	5,323,216	5,876,869	5,569,541	307,328
Jun-19	21,954	6,047,154	6,069,108	5,751,727	317,381
Jul-19	79,828	6,314,318	6,394,145	6,059,766	334,379
Aug-19	(143,966)	6,191,454	6,047,487	5,731,237	316,251
Sep-19	(230,605)	6,044,647	5,814,042	5,509,999	304,043
Oct-19	(206,545)	5,654,666	5,448,121	5,163,214	284,907
Nov-19	(279,592)	4,858,856	4,579,263	4,339,793	239,471
Dec-19	(18,346)	4,615,297	4,596,951	4,356,556	240,396
TOTAL		124,337,565	124,535,676	118,023,138	6,512,538

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 44
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: E. J. Anderson EJA-5

FLORIDA POWER & LIGHT COMPANY
SOBRA PROVISION FOR REFUND INTEREST

	REFUND ACCRUAL	CUMULATIVE REFUND	INTEREST RATE	CUM. REFUND WITH INTEREST	MONTHLY INTEREST	CUMULATIVE INTEREST
Jan-18	239,160	239,160	0.0012667	239,311	151	151
Feb-18	216,664	455,824	0.0012833	456,422	446	598
Mar-18	232,788	688,612	0.0014500	690,040	831	1,428
Apr-18	251,226	939,838	0.0015458	942,527	1,261	2,689
May-18	260,206	1,200,044	0.0015458	1,204,391	1,658	4,347
Jun-18	292,610	1,492,654	0.0016000	1,499,163	2,161	6,508
Jul-18	316,819	1,809,473	0.0016500	1,818,717	2,735	9,243
Aug-18	318,743	2,128,216	0.0016500	2,140,723	3,264	12,507
Sep-18	306,553	2,434,769	0.0017458	2,451,281	4,005	16,512
Oct-18	293,618	2,728,387	0.0018667	2,749,749	4,850	21,362
Nov-18	246,712	2,975,099	0.0019042	3,001,932	5,471	26,833
Dec-18	232,353	3,207,452	0.0019667	3,240,417	6,132	32,965
Jan-19	224,543	3,431,995	0.0020167	3,471,721	6,761	39,726
Feb-19	227,007	3,659,001	0.0020125	3,705,943	7,215	46,941
Mar-19	239,388	3,898,390	0.0020375	3,953,126	7,795	54,736
Apr-19	269,993	4,168,383	0.0020458	4,231,483	8,364	63,100
May-19	307,328	4,475,711	0.0020083	4,547,618	8,807	71,907
Jun-19	317,381	4,793,092	0.0019625	4,874,235	9,236	81,143
Jul-19	334,379	5,127,471	0.0018417	5,217,899	9,285	90,427
Aug-19	316,251	5,443,722	0.0018417	5,544,050	9,901	100,328
Sep-19	304,043	5,747,765	0.0018417	5,858,583	10,490	110,819
Oct-19	284,907	6,032,672	0.0018417	6,154,542	11,052	121,870
Nov-19	239,471	6,272,142	0.0018417	6,405,568	11,555	133,426
Dec-19	240,396	6,512,538	0.0018417	6,657,982	12,018	145,444
TOTAL	6,512,538				145,444	
				Total Cumulative Refund with Interest	6,657,982	

FLORIDA POWER & LIGHT COMPANY
2017 SOBRA PROSPECTIVE ADJUSTMENT
FOR JANUARY 1, 2020

2017 SOBRA PROSPECTIVE ADJUSTMENT	**($Million)**	**Source**
(A) Jurisdictional Annualized Revenue Requirement	($3.152)	Exhibit LF-2 as Filed
(B) Total Retail Base Revenues From the Sales of Electricity	6,927.744	Exhibit EJA-7 Page 1 of 1
(C) SoBRA ADJUSTMENT FACTOR [(A) / (B)]	-0.045%	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 45
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: E. J. Anderson EJA-6

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 46
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: E. J. Anderson EJA-7

FLORIDA POWER & LIGHT COMPANY
RETAIL BASE REVENUES
12 MONTHS BEGINNING JANUARY 2020

Customer Class	2020 Jan	Feb	Mar	Apr	May	Jun	Jul
Residential	318,278,054	282,468,525	291,035,540	311,468,130	352,900,171	407,587,877	447,433,621
Commercial	186,726,875	174,203,143	183,450,084	192,528,598	201,000,444	207,290,689	212,250,769
Industrial	7,418,611	7,538,366	7,456,881	7,522,832	7,571,677	7,815,067	7,598,209
Street & Highway	5,330,625	4,906,142	5,936,120	5,516,512	5,477,543	5,404,630	5,417,761
Other	129,976	148,482	150,531	140,854	136,608	124,242	129,414
Railroads & Railways	292,762	307,698	292,103	300,825	332,624	318,631	337,873
Total Jurisdictional Billed Revenue	518,176,903	469,572,356	488,321,259	517,477,750	567,419,066	628,541,137	673,167,648
CILC/CDR Incentive	5,149,363	5,593,982	5,062,524	5,398,895	5,844,962	8,838,350	6,717,630
Unbilled Revenue	316,836	287,117	298,581	316,408	346,945	384,317	411,604
Total Retail Base Revenues From the Sales of Electricity	$ 523,643,102	$ 475,453,455	$ 493,682,364	$ 523,193,054	$ 573,610,973	$ 637,763,804	$ 680,296,881

Customer Class	2020 Aug	Sept	Oct	Nov	Dec	12 Months Ending
Residential	451,409,365	435,980,369	397,706,127	325,308,076	304,193,905	4,325,769,760
Commercial	211,327,193	210,754,235	207,236,488	191,838,486	187,591,643	2,366,198,646
Industrial	7,441,425	7,612,325	7,489,551	7,465,694	7,531,592	90,462,229
Street & Highway	5,841,052	5,661,450	5,206,466	6,010,333	5,599,616	66,308,251
Other	121,595	133,395	144,263	146,200	139,875	1,645,435
Railroads & Railways	356,300	345,469	324,345	324,932	325,032	3,858,595
Total Jurisdictional Billed Revenue	676,496,929	660,487,243	618,107,241	531,093,722	505,381,663	6,854,242,915
CILC/CDR Incentive Credit	8,198,504	5,268,095	5,711,124	5,185,892	5,492,380	72,461,702
Unbilled Revenue	413,640	403,851	377,938	324,734	309,012	4,190,981
Total Retail Base Revenues From the Sales of Electricity	$ 685,109,073	$ 666,159,188	$ 624,196,302	$ 536,604,348	$ 511,183,055	$ 6,930,895,598
Adjustment for 2017 Project True-Up						$ (3,152,009) *
Adjusted Retail Base Revenues From the Sales of Electricity						$ 6,927,743,590

* Refer to Exhibit EJA-4 Page 1 of 1

Totals may not add due to rounding

Docket No. 20190001-EI
Projected Retail Base Revenues for January 1, 2020
Exhibit EJA-7, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 47
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: E. J. Anderson EJA-8

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JANUARY 1, 2020 RATES ADJUSTED FOR 2017 SOBRA TRUE-UP

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	RS-1	Residential Service				
2		Customer Charge/Minimum	$8.28	$8.28	$0.00	0.0%
3						
4		Base Energy Charge (¢ per kWh)				
5		First 1,000 kWh	6.118	6.115	(0.003)	0.0%
6		All additional kWh	7.173	7.170	(0.003)	0.0%
7						
8						
9	RTR-1	Residential Service -Time of Use				
10		Customer Charge/Minimum	$8.28	$8.28	$0.00	0.0%
11						
12		Base Energy Charge (¢ per kWh)				
13		On-Peak	10.914	10.909	(0.005)	0.0%
14		Off-Peak	(4.855)	(4.853)	0.002	0.0%
15						
16						
17	GS-1	General Service - Non Demand (0-20 kW)				
18		Customer Charge/Minimum				
19		Metered	$10.54	$10.54	$0.00	0.0%
20		Unmetered Service Credit	($5.26)	($5.26)	$0.00	0.0%
21						
22		Base Energy Charge (¢ per kWh)	5.972	5.969	(0.003)	-0.1%
23						
24						
25	GST-1	General Service - Non Demand - Time of Use (0-20 kW)				
26		Customer Charge/Minimum	$10.54	$10.54	$0.00	0.0%
27						
28		Base Energy Charge (¢ per kWh)				
29		On-Peak	11.027	11.022	(0.005)	0.0%
30		Off-Peak	3.776	3.774	(0.002)	-0.1%
31						
32						
33						
34						
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42						

* April 1, 2019 Rates approved in Docket No. 20180001-EI

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	GSD-1	General Service Demand (21-499 kW)				
2		Customer Charge	$26.32	$26.31	($0.01)	0.0%
3						
4		Demand Charge ($/kW)	$9.91	$9.91	$0.00	0.0%
5						
6		Base Energy Charge (¢ per kWh)	2.207	2.206	(0.001)	0.0%
7						
8						
9	GSDT-1	General Service Demand - Time of Use (21-499 kW)				
10		Customer Charge	$26.32	$26.31	($0.01)	0.0%
11						
12		Demand Charge - On-Peak ($/kW)	$9.91	$9.91	$0.00	0.0%
13						
14		Base Energy Charge (¢ per kWh)				
15		On-Peak	4.502	4.500	(0.002)	0.0%
16		Off-Peak	1.191	1.190	(0.001)	-0.1%
17						
18						
19	GSLD-1	General Service Large Demand (500-1999 kW)				
20		Customer Charge	$78.91	$78.87	($0.04)	-0.1%
21						
22		Demand Charge ($/kW)	$12.11	$12.10	($0.01)	-0.1%
23						
24		Base Energy Charge (¢ per kWh)	1.743	1.742	(0.001)	-0.1%
25						
26						
27	GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)				
28		Customer Charge	$78.91	$78.87	($0.04)	-0.1%
29						
30		Demand Charge - On-Peak ($/kW)	$12.11	$12.10	($0.01)	-0.1%
31						
32		Base Energy Charge (¢ per kWh)				
33		On-Peak	2.853	2.852	(0.001)	0.0%
34		Off-Peak	1.258	1.257	(0.001)	-0.1%
35						
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CS-1	Curtailable Service (500-1999 kW)				
2		Customer Charge	$105.22	$105.17	($0.05)	0.0%
3						
4		Demand Charge ($/kW)	$12.11	$12.10	($0.01)	-0.1%
5						
6		Base Energy Charge (¢ per kWh)	1.743	1.742	(0.001)	-0.1%
7						
8		Monthly Credit ($ per kW)	($2.04)	($2.04)	$0.00	0.0%
9						
10		Charges for Non-Compliance of Curtailment Demand				
11		Rebilling for last 36 months (per kW)	$2.04	$2.04	$0.00	0.0%
12		Penalty Charge-current month (per kW)	$4.38	$4.38	$0.00	0.0%
13		Early Termination Penalty charge (per kW)	$1.29	$1.29	$0.00	0.0%
14						
15	CST-1	Curtailable Service -Time of Use (500-1999 kW)				
16		Customer Charge	$105.22	$105.17	($0.05)	0.0%
17						
18		Demand Charge - On-Peak ($/kW)	$12.11	$12.10	($0.01)	-0.1%
19						
20		Base Energy Charge (¢ per kWh)				
21		On-Peak	2.853	2.852	(0.001)	0.0%
22		Off-Peak	1.258	1.257	(0.001)	-0.1%
23						
24		Monthly Credit ($ per kW)	($2.04)	($2.04)	$0.00	0.0%
25						
26		Charges for Non-Compliance of Curtailment Demand				
27		Rebilling for last 36 months (per kW)	$2.04	$2.04	$0.00	0.0%
28		Penalty Charge-current month (per kW)	$4.38	$4.38	$0.00	0.0%
29		Early Termination Penalty charge (per kW)	$1.29	$1.29	$0.00	0.0%
30						
31	GSLD-2	General Service Large Demand (2000 kW +)				
32		Customer Charge	$236.55	$236.44	($0.11)	0.0%
33						
34		Demand Charge ($/kW)	$12.61	$12.60	($0.01)	-0.1%
35						
36		Base Energy Charge (¢ per kWh)	1.569	1.568	(0.001)	-0.1%
37						
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	GSLDT-2	General Service Large Demand - Time of Use (2000 kW +)				
2		Customer Charge	$236.55	$236.44	($0.11)	0.0%
3						
4		Demand Charge - On-Peak ($/kW)	$12.61	$12.60	($0.01)	-0.1%
5						
6		Base Energy Charge (¢ per kWh)				
7		On-Peak	2.435	2.434	(0.001)	0.0%
8		Off-Peak	1.229	1.228	(0.001)	-0.1%
9						
10						
11	CS-2	Curtailable Service (2000 kW +)				
12		Customer Charge	$262.83	$262.71	($0.12)	0.0%
13						
14		Demand Charge ($/kW)	$12.61	$12.60	($0.01)	-0.1%
15						
16		Base Energy Charge (¢ per kWh)	1.569	1.568	(0.001)	-0.1%
17						
18		Monthly Credit (per kW)	($2.04)	($2.04)	$0.00	0.0%
19						
20		Charges for Non-Compliance of Curtailment Demand				
21		Rebilling for last 36 months (per kW)	$2.04	$2.04	$0.00	0.0%
22		Penalty Charge-current month (per kW)	$4.37	$4.37	$0.00	0.0%
23		Early Termination Penalty charge (per kW)	$1.29	$1.29	$0.00	0.0%
24						
25	CST-2	Curtailable Service -Time of Use (2000 kW +)				
26		Customer Charge	$262.83	$262.71	($0.12)	0.0%
27						
28		Demand Charge - On-Peak ($/kW)	$12.61	$12.60	($0.01)	-0.1%
29						
30		Base Energy Charge (¢ per kWh)				
31		On-Peak	2.435	2.434	(0.001)	0.0%
32		Off-Peak	1.229	1.228	(0.001)	-0.1%
33						
34		Monthly Credit (per kW)	($2.04)	($2.04)	$0.00	0.0%
35						
36		Charges for Non-Compliance of Curtailment Demand				
37		Rebilling for last 36 months (per kW)	$2.04	$2.04	$0.00	0.0%
38		Penalty Charge-current month (per kW)	$4.37	$4.37	$0.00	0.0%
39		Early Termination Penalty charge (per kW)	$1.29	$1.29	$0.00	0.0%
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	GSLD-3	General Service Large Demand (2000 kW +)				
2		Customer Charge	$2,100.35	$2,099.40	($0.95)	0.0%
3						
4		Demand Charge ($/kW)	$9.77	$9.77	$0.00	0.0%
5						
6		Base Energy Charge (¢ per kWh)	1.128	1.127	(0.001)	-0.1%
7						
8						
9	GSLDT-3	General Service Large Demand - Time of Use (2000 kW +)				
10		Customer Charge	$2,100.35	$2,099.40	($0.95)	0.0%
11						
12		Demand Charge - On-Peak ($/kW)	$9.77	$9.77	$0.00	0.0%
13						
14		Base Energy Charge (¢ per kWh)				
15		On-Peak	1.288	1.287	(0.001)	-0.1%
16		Off-Peak	1.070	1.070	0.000	0.0%
17						
18						
19	CS-3	Curtailable Service (2000 kW +)				
20		Customer Charge	$2,126.61	$2,125.65	($0.96)	0.0%
21						
22		Demand Charge ($/kW)	$9.77	$9.77	$0.00	0.0%
23						
24		Base Energy Charge (¢ per kWh)	1.128	1.127	(0.001)	-0.1%
25						
26		Monthly Credit (per kW)	($2.04)	($2.04)	$0.00	0.0%
27						
28		Charges for Non-Compliance of Curtailment Demand				
29		Rebilling for last 36 months (per kW)	$2.04	$2.04	$0.00	0.0%
30		Penalty Charge-current month (per kW)	$4.37	$4.37	$0.00	0.0%
31		Early Termination Penalty charge (per kW)	$1.29	$1.29	$0.00	0.0%
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CST-3	Curtailable Service -Time of Use (2000 kW +)				
2		Customer Charge	$2,126.61	$2,125.65	($0.96)	0.0%
3						
4		Demand Charge - On-Peak ($/kW)	$9.77	$9.77	$0.00	0.0%
5						
6		Base Energy Charge (¢ per kWh)				
7		On-Peak	1.288	1.287	(0.001)	-0.1%
8		Off-Peak	1.070	1.070	0.000	0.0%
9						
10		Monthly Credit (per kW)	($2.04)	($2.04)	$0.00	0.0%
11						
12		Charges for Non-Compliance of Curtailment Demand				
13		Rebilling for last 36 months (per kW)	$2.04	$2.04	$0.00	0.0%
14		Penalty Charge-current month (per kW)	$4.37	$4.37	$0.00	0.0%
15		Early Termination Penalty charge (per kW)	$1.29	$1.29	$0.00	0.0%
16						
17	OS-2	Sports Field Service [Schedule closed to new customers]				
18		Customer Charge	$131.95	$131.89	($0.06)	0.0%
19						
20		Base Energy Charge (¢ per kWh)	8.303	8.299	(0.004)	0.0%
21						
22						
23	MET	Metropolitan Transit Service				
24		Customer Charge	$631.74	$631.46	($0.28)	0.0%
25						
26		Base Demand Charge ($/kW)	$13.37	$13.36	($0.01)	-0.1%
27						
28		Base Energy Charge (¢ per kWh)	1.784	1.783	(0.001)	-0.1%
29						
30						
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CILC-1	Commercial/Industrial Load Control Program [Schedule closed to new customers]				
2		Customer Charge				
3		(G) 200-499kW	$157.63	$157.56	($0.07)	0.0%
4		(D) above 500kW	$262.36	$262.24	($0.12)	0.0%
5		(T) transmission	$2,326.81	$2,325.76	($1.05)	0.0%
6						
7		Base Demand Charge ($/kW)				
8		per kW of Max Demand All kW:				
9		(G) 200-499kW	$4.20	$4.20	$0.00	0.0%
10		(D) above 500kW	$4.41	$4.41	$0.00	0.0%
11		(T) transmission	None	None	None	N/A
12						
13						
14		per kW of Load Control On-Peak:				
15		(G) 200-499kW	$2.76	$2.76	$0.00	0.0%
16		per kW of Load Control On-Peak:				
17		(D) above 500kW	$3.15	$3.15	$0.00	0.0%
18		(T) transmission	$3.35	$3.35	$0.00	0.0%
19						
20						
21						
22		Per kW of Firm On-Peak Demand				
23		(G) 200-499kW	$10.50	$10.50	$0.00	0.0%
24		(D) above 500kW	$11.44	$11.43	($0.01)	-0.1%
25		(T) transmission	$12.23	$12.22	($0.01)	-0.1%
26						
27		Base Energy Charge (¢ per kWh)				
28		On-Peak				
29		(G) 200-499kW	1.566	1.565	(0.001)	-0.1%
30		(D) above 500kW	1.053	1.053	0.000	0.0%
31		(T) transmission	0.977	0.977	0.000	0.0%
32		Off-Peak				
33		(G) 200-499kW	1.566	1.565	(0.001)	-0.1%
34		(D) above 500kW	1.053	1.053	0.000	0.0%
35		(T) transmission	0.977	0.977	0.000	0.0%
36						
37		Excess "Firm Demand" or Termination Charge				
38		¤ Up to prior 60 months of service	Difference between Firm and			
39			Load-Control On-Peak Demand Charge			
40						
41		¤ Penalty Charge per kW for each month of rebilling	$1.13	$1.13	$0.00	0.0%
42						

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CDR		Commercial/Industrial Demand Reduction Rider				
2			Monthly Rate				
3			Customer Charge	Otherwise Applicable Rate			
4			Demand Charge	Otherwise Applicable Rate			
5			Energy Charge	Otherwise Applicable Rate			
6							
7			Monthly Administrative Adder				
8			GSD-1	$131.62	$131.56	($0.06)	0.0%
9			GSDT-1	$131.62	$131.56	($0.06)	0.0%
10			GSLD-1, GSLDT-1	$184.12	$184.04	($0.08)	0.0%
11			GSLD-2, GSLDT-2	$78.85	$78.81	($0.04)	-0.1%
12			GSLD-3, GSLDT-3	$236.29	$236.18	($0.11)	0.0%
13			HLFT	Applicable General Service Level Rate			
14			SDTR	Applicable General Service Level Rate			
15							
16			Utility Controlled Demand Credit $/kW	($8.65)	($8.65)	$0.00	0.0%
17							
18			Excess "Firm Demand"	$8.65	$8.65	$0.00	0.0%
19			¤ Up to prior 60 months of service				
20							
21			¤ Penalty Charge per kW for	$1.13	$1.13	$0.00	0.0%
22			each month of rebilling				
23							
24	SL-1		Street Lighting				
25			Charges for FPL-Owned Units				
26			Fixture				
27			Sodium Vapor 6,300 lu 70 watts	$4.11	$4.11	$0.00	0.0%
28			Sodium Vapor 9,500 lu 100 watts	$4.18	$4.18	$0.00	0.0%
29			Sodium Vapor 16,000 lu 150 watts	$4.31	$4.31	$0.00	0.0%
30			Sodium Vapor 22,000 lu 200 watts	$6.53	$6.53	$0.00	0.0%
31			Sodium Vapor 50,000 lu 400 watts	$6.59	$6.59	$0.00	0.0%
32		**	Sodium Vapor 27,500 lu 250 watts	$6.94	$6.94	$0.00	0.0%
33		**	Sodium Vapor 140,000 lu 1,000 watts	$10.46	$10.46	$0.00	0.0%
34		**	Mercury Vapor 6,000 lu 140 watts	$3.25	$3.25	$0.00	0.0%
35		**	Mercury Vapor 8,600 lu 175 watts	$3.31	$3.31	$0.00	0.0%
36		**	Mercury Vapor 11,500 lu 250 watts	$5.50	$5.50	$0.00	0.0%
37		**	Mercury Vapor 21,500 lu 400 watts	$5.47	$5.47	$0.00	0.0%
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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE		(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SL-1		Street Lighting (continued))					
2			Maintenance					
3			Sodium Vapor 6,300 lu 70 watts		$1.97	$1.97	$0.00	0.0%
4			Sodium Vapor 9,500 lu 100 watts		$1.98	$1.98	$0.00	0.0%
5			Sodium Vapor 16,000 lu 150 watts		$2.01	$2.01	$0.00	0.0%
6			Sodium Vapor 22,000 lu 200 watts		$2.55	$2.55	$0.00	0.0%
7			Sodium Vapor 50,000 lu 400 watts		$2.56	$2.56	$0.00	0.0%
8		**	Sodium Vapor 27,500 lu 250 watts		$2.77	$2.77	$0.00	0.0%
9		**	Sodium Vapor 140,000 lu 1,000 watts		$4.97	$4.97	$0.00	0.0%
10		**	Mercury Vapor 6,000 lu 140 watts		$1.76	$1.76	$0.00	0.0%
11		**	Mercury Vapor 8,600 lu 175 watts		$1.76	$1.76	$0.00	0.0%
12		**	Mercury Vapor 11,500 lu 250 watts		$2.53	$2.53	$0.00	0.0%
13		**	Mercury Vapor 21,500 lu 400 watts		$2.49	$2.49	$0.00	0.0%
14								
15			Energy Non-Fuel	kWh				
16			Sodium Vapor 6,300 lu 70 watts	29	$0.88	$0.88	$0.00	0.0%
17			Sodium Vapor 9,500 lu 100 watts	41	$1.25	$1.25	$0.00	0.0%
18			Sodium Vapor 16,000 lu 150 watts	60	$1.83	$1.82	($0.01)	-0.5%
19			Sodium Vapor 22,000 lu 200 watts	88	$2.68	$2.68	$0.00	0.0%
20			Sodium Vapor 50,000 lu 400 watts	168	$5.11	$5.11	$0.00	0.0%
21		**	Sodium Vapor 27,500 lu 250 watts	116	$3.53	$3.53	$0.00	0.0%
22		**	Sodium Vapor 140,000 lu 1,000 watts	411	$12.50	$12.50	$0.00	0.0%
23		**	Mercury Vapor 6,000 lu 140 watts	62	$1.89	$1.89	$0.00	0.0%
24		**	Mercury Vapor 8,600 lu 175 watts	77	$2.34	$2.34	$0.00	0.0%
25		**	Mercury Vapor 11,500 lu 250 watts	104	$3.16	$3.16	$0.00	0.0%
26		**	Mercury Vapor 21,500 lu 400 watts	160	$4.87	$4.87	$0.00	0.0%
27								
28								
29			Note: The proposed monthly Non-Fuel Energy charge is calculated by multiplying the kWh rating for each fixture by the proposed					
30			Non-Fuel Energy Rate. This avoids rounding issues caused by separating the increases into the various components.					
31			**Note: These units are closed to new Company installations.					
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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE			(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SL-1		Street Lighting (continued))						
2			Charge for Customer-Owned Units						
3			Relamping and Energy						
4			Sodium Vapor 6,300 lu 70 watts			$2.86	$2.86	$0.00	0.0%
5			Sodium Vapor 9,500 lu 100 watts			$3.24	$3.24	$0.00	0.0%
6			Sodium Vapor 16,000 lu 150 watts			$3.85	$3.84	($0.01)	-0.3%
7			Sodium Vapor 22,000 lu 200 watts			$5.20	$5.20	$0.00	0.0%
8			Sodium Vapor 50,000 lu 400 watts			$7.64	$7.64	$0.00	0.0%
10		**	Sodium Vapor 27,500 lu 250 watts			$6.27	$6.27	$0.00	0.0%
11		**	Sodium Vapor 140,000 lu 1,000 watts			$17.51	$17.51	$0.00	0.0%
12		**	Mercury Vapor 6,000 lu 140 watts			$3.66	$3.66	$0.00	0.0%
13		**	Mercury Vapor 8,600 lu 175 watts			$4.11	$4.11	$0.00	0.0%
14		**	Mercury Vapor 11,500 lu 250 watts			$5.71	$5.71	$0.00	0.0%
15		**	Mercury Vapor 21,500 lu 400 watts			$7.37	$7.37	$0.00	0.0%
18									
19			Energy Only	kWh					
20			Sodium Vapor 6,300 lu 70 watts		29	$0.88	$0.88	$0.00	0.0%
21			Sodium Vapor 9,500 lu 100 watts		41	$1.25	$1.25	$0.00	0.0%
22			Sodium Vapor 16,000 lu 150 watts		60	$1.83	$1.82	($0.01)	-0.5%
23			Sodium Vapor 22,000 lu 200 watts		88	$2.68	$2.68	$0.00	0.0%
24			Sodium Vapor 50,000 lu 400 watts		168	$5.11	$5.11	$0.00	0.0%
26		**	Sodium Vapor 27,500 lu 250 watts		116	$3.53	$3.53	$0.00	0.0%
27		**	Sodium Vapor 140,000 lu 1,000 watts		411	$12.50	$12.50	$0.00	0.0%
28		**	Mercury Vapor 6,000 lu 140 watts		62	$1.89	$1.89	$0.00	0.0%
29		**	Mercury Vapor 8,600 lu 175 watts		77	$2.34	$2.34	$0.00	0.0%
30		**	Mercury Vapor 11,500 lu 250 watts		104	$3.16	$3.16	$0.00	0.0%
31		**	Mercury Vapor 21,500 lu 400 watts		160	$4.87	$4.87	$0.00	0.0%
34									
35			Non-Fuel Energy (¢ per kWh)			3.042	3.041	(0.001)	0.0%
36									
37									
38			Note: The monthly Relamp and Energy charge is calculated by adding the Relamp increase to the Energy-only increase avoiding rounding issues.						
39			**Note: These units are closed to new Company installations.						
40									
41									
42									

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SL-1	Street Lighting (continued))					
2		Other Charges					
3		Wood Pole		$5.20	$5.20	$0.00	0.0%
4		Concrete Pole / Steel Pole		$7.11	$7.11	$0.00	0.0%
5		Fiberglass Pole		$8.42	$8.42	$0.00	0.0%
6		Underground conductors not under paving (¢ per foot)		4.026	4.024	(0.002)	0.0%
7		Underground conductors under paving (¢ per foot)		9.835	9.831	(0.004)	0.0%
8							
9		Willful Damage					
10		Cost for Shield upon second occurrence		$280.00	$280.00	$0.00	0.0%
11							
12	SL-1M	Street Lighting					
13							
14		Customer Charge/Minimum		$14.79	$14.78	($0.01)	-0.1%
15		Base Energy Charge (¢ per kWh)		2.986	2.985	(0.001)	0.0%
16							
17							
18							
19	PL-1	Premium Lighting					
20		Present Value Revenue Requirement					
21		Multiplier		1.1961	1.1961	0.000	0.0%
22							
23		Monthly Rate					
24		Facilities (Percentage of total work order cost)					
25		10 Year Payment Option		1.364%	1.364%	0.000	0.0%
26		20 Year Payment Option		0.926%	0.926%	0.000	0.0%
27							
28		Maintenance		FPL's estimated cost of maintaining facilities			
29							
30							
31		Termination Factors					
32		10 Year Payment Option					
33			1	1.1961	1.1961	0.000	0.0%
34			2	1.0324	1.0324	0.000	0.0%
35			3	0.9489	0.9489	0.000	0.0%
36			4	0.8590	0.8590	0.000	0.0%
37			5	0.7621	0.7621	0.000	0.0%
38			6	0.6576	0.6576	0.000	0.0%
39							
40							
41							
42							

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	PL-1	Premium Lighting (continued)					
2			7	0.5450	0.5450	0.000	0.0%
3			8	0.4237	0.4237	0.000	0.0%
4			9	0.2929	0.2929	0.000	0.0%
5			10	0.1519	0.1519	0.000	0.0%
6			>10	0.0000	0.0000	0.000	
7							
8		20 Year Payment Option					
9			1	1.1961	1.1961	0.000	0.0%
10			2	1.0850	1.0850	0.000	0.0%
11			3	1.0582	1.0582	0.000	0.0%
12			4	1.0293	1.0293	0.000	0.0%
13			5	0.9982	0.9982	0.000	0.0%
14			6	0.9646	0.9646	0.000	0.0%
15			7	0.9285	0.9285	0.000	0.0%
16			8	0.8895	0.8895	0.000	0.0%
17			9	0.8475	0.8475	0.000	0.0%
18			10	0.8023	0.8023	0.000	0.0%
19			11	0.7535	0.7535	0.000	0.0%
20			12	0.7009	0.7009	0.000	0.0%
21			13	0.6443	0.6443	0.000	0.0%
22			14	0.5832	0.5832	0.000	0.0%
23			15	0.5174	0.5174	0.000	0.0%
24			16	0.4465	0.4465	0.000	0.0%
25			17	0.3700	0.3700	0.000	0.0%
26			18	0.2876	0.2876	0.000	0.0%
27			19	0.1988	0.1988	0.000	0.0%
28			20	0.1031	0.1031	0.000	0.0%
29			>20	0.0000	0.0000	0.000	
30							
31		Non-Fuel Energy (¢ per kWh)		3.042	3.041	(0.001)	0.0%
32							
33		Willful Damage					
34		All occurrences after initial repair		Cost for repair or replacement			
35							
36	RL-1	Recreational Lighting [Schedule closed to new customers]					
37							
38		Non-Fuel Energy (¢ per kWh)		Otherwise applicable General			
39				Service Rate			
40							
41		Maintenance		FPL's estimated cost of maintaining facilities			
42							

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE		(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	OL-1		Outdoor Lighting					
2			Charges for FPL-Owned Units					
3			Fixture					
4			Sodium Vapor 6,300 lu 70 watts		$5.34	$5.34	$0.00	0.0%
5			Sodium Vapor 9,500 lu 100 watts		$5.45	$5.45	$0.00	0.0%
6			Sodium Vapor 16,000 lu 150 watts		$5.64	$5.64	$0.00	0.0%
7			Sodium Vapor 22,000 lu 200 watts		$8.20	$8.20	$0.00	0.0%
8			Sodium Vapor 50,000 lu 400 watts		$8.75	$8.75	$0.00	0.0%
9		**	Sodium Vapor 12,000 lu 150 watts		$5.64	$5.64	$0.00	0.0%
10		**	Mercury Vapor 6,000 lu 140 watts		$4.10	$4.10	$0.00	0.0%
11		**	Mercury Vapor 8,600 lu 175 watts		$4.12	$4.12	$0.00	0.0%
12		**	Mercury Vapor 21,500 lu 400 watts		$6.75	$6.75	$0.00	0.0%
13								
14			Maintenance					
15			Sodium Vapor 6,300 lu 70 watts		$2.02	$2.02	$0.00	0.0%
16			Sodium Vapor 9,500 lu 100 watts		$2.02	$2.02	$0.00	0.0%
17			Sodium Vapor 16,000 lu 150 watts		$2.05	$2.05	$0.00	0.0%
18			Sodium Vapor 22,000 lu 200 watts		$2.63	$2.63	$0.00	0.0%
19			Sodium Vapor 50,000 lu 400 watts		$2.59	$2.59	$0.00	0.0%
20		**	Sodium Vapor 12,000 lu 150 watts		$2.05	$2.05	$0.00	0.0%
21		**	Mercury Vapor 6,000 lu 140 watts		$1.80	$1.80	$0.00	0.0%
22		**	Mercury Vapor 8,600 lu 175 watts		$1.80	$1.80	$0.00	0.0%
23		**	Mercury Vapor 21,500 lu 400 watts		$2.53	$2.53	$0.00	0.0%
24								
25			Energy Non-Fuel	kWh				
26			Sodium Vapor 6,300 lu 70 watts	29	$0.94	$0.94	0.00	0.0%
27			Sodium Vapor 9,500 lu 100 watts	41	$1.33	$1.33	0.00	0.0%
28			Sodium Vapor 16,000 lu 150 watts	60	$1.95	$1.95	0.00	0.0%
29			Sodium Vapor 22,000 lu 200 watts	88	$2.86	$2.86	0.00	0.0%
30			Sodium Vapor 50,000 lu 400 watts	168	$5.45	$5.45	0.00	0.0%
31		**	Sodium Vapor 12,000 lu 150 watts	60	$1.95	$1.95	0.00	0.0%
32		**	Mercury Vapor 6,000 lu 140 watts	62	$2.01	$2.01	0.00	0.0%
33		**	Mercury Vapor 8,600 lu 175 watts	77	$2.50	$2.50	0.00	0.0%
34		**	Mercury Vapor 21,500 lu 400 watts	160	$5.20	$5.19	(0.01)	-0.2%
35								
36								
37								
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Note: The monthly Relamp and Energy charge is calculated by adding the Relamp increase to the Energy-only increase avoiding rounding issues.
**Note: These units are closed to new Company installations.

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE			(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	OL-1		Outdoor Lighting (continued)						
2			Charges for Customer Owned Units						
3			Total Charge-Relamping & Energy						
4			Sodium Vapor 6,300 lu 70 watts			$2.91	$2.91	$0.00	0.0%
5			Sodium Vapor 9,500 lu 100 watts			$3.30	$3.30	$0.00	0.0%
6			Sodium Vapor 16,000 lu 150 watts			$3.95	$3.95	$0.00	0.0%
7			Sodium Vapor 22,000 lu 200 watts			$5.43	$5.43	$0.00	0.0%
8			Sodium Vapor 50,000 lu 400 watts			$7.97	$7.97	$0.00	0.0%
9		**	Sodium Vapor 12,000 lu 150 watts			$4.23	$4.23	$0.00	0.0%
10		**	Mercury Vapor 6,000 lu 140 watts			$3.77	$3.77	$0.00	0.0%
11		**	Mercury Vapor 8,600 lu 175 watts			$4.26	$4.26	$0.00	0.0%
12		**	Mercury Vapor 21,500 lu 400 watts			$7.67	$7.66	($0.01)	-0.1%
13									
14			Energy Only	kWh					
15			Sodium Vapor 6,300 lu 70 watts		29	$0.94	$0.94	$0.00	0.0%
16			Sodium Vapor 9,500 lu 100 watts		41	$1.33	$1.33	$0.00	0.0%
17			Sodium Vapor 16,000 lu 150 watts		60	$1.95	$1.95	$0.00	0.0%
18			Sodium Vapor 22,000 lu 200 watts		88	$2.86	$2.86	$0.00	0.0%
19			Sodium Vapor 50,000 lu 400 watts		168	$5.45	$5.45	$0.00	0.0%
20		**	Sodium Vapor 12,000 lu 150 watts		60	$1.95	$1.95	$0.00	0.0%
21		**	Mercury Vapor 6,000 lu 140 watts		62	$2.01	$2.01	$0.00	0.0%
22		**	Mercury Vapor 8,600 lu 175 watts		77	$2.50	$2.50	$0.00	0.0%
23		**	Mercury Vapor 21,500 lu 400 watts		160	$5.20	$5.19	($0.01)	-0.2%
24									
25			Non-Fuel Energy (¢ per kWh)			3.247	3.246	(0.001)	0.0%
26									
27			Other Charges						
28			Wood Pole			$11.76	$11.75	($0.01)	-0.1%
29			Concrete Pole / Steel Pole			$15.89	$15.88	($0.01)	-0.1%
30			Fiberglass Pole			$18.67	$18.66	($0.01)	-0.1%
31			Underground conductors excluding						
32			Trenching per foot			$0.090	$0.090	$0.000	0.0%
33			Down-guy, Anchor and Protector			$10.69	$10.69	$0.00	0.0%
34									
35	SL-2		Traffic Signal Service						
36			Minimum Charge at each point			$3.41	$3.41	$0.00	0.0%
37			Base Energy Charge (¢ per kWh)			4.981	4.979	(0.002)	0.0%
38									
39	SL-2M		Traffic Signal Service						
40			Customer Charge/Minimum			$6.33	$6.33	$0.00	0.0%
41			Base Energy Charge (¢ per kWh)			4.840	4.838	(0.002)	0.0%
42									

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SST-1	Standby and Supplemental Service				
2		Customer Charge				
3		SST-1(D1)	$131.84	$131.78	($0.06)	0.0%
4		SST-1(D2)	$131.84	$131.78	($0.06)	0.0%
5		SST-1(D3)	$448.24	$448.04	($0.20)	0.0%
6		SST-1(T)	$1,900.79	$1,899.93	($0.86)	0.0%
7						
8		Distribution Demand $/kW Contract Standby Demand				
9		SST-1(D1)	$3.16	$3.16	$0.00	0.0%
10		SST-1(D2)	$3.16	$3.16	$0.00	0.0%
11		SST-1(D3)	$3.16	$3.16	$0.00	0.0%
12		SST-1(T)	N/A	N/A	N/A	N/A
13						
14		Reservation Demand $/kW				
15		SST-1(D1)	$1.56	$1.56	$0.00	0.0%
16		SST-1(D2)	$1.56	$1.56	$0.00	0.0%
17		SST-1(D3)	$1.56	$1.56	$0.00	0.0%
18		SST-1(T)	$1.42	$1.42	$0.00	0.0%
19						
20		Daily Demand (On-Peak) $/kW				
21		SST-1(D1)	$0.75	$0.75	$0.00	0.0%
22		SST-1(D2)	$0.75	$0.75	$0.00	0.0%
23		SST-1(D3)	$0.75	$0.75	$0.00	0.0%
24		SST-1(T)	$0.45	$0.45	$0.00	0.0%
25						
26		Supplemental Service				
27		Demand	Otherwise Applicable Rate			
28		Energy	Otherwise Applicable Rate			
29						
30		Non-Fuel Energy - On-Peak (¢ per kWh)				
31		SST-1(D1)	0.751	0.751	0.000	0.0%
32		SST-1(D2)	0.751	0.751	0.000	0.0%
33		SST-1(D3)	0.751	0.751	0.000	0.0%
34		SST-1(T)	0.748	0.748	0.000	0.0%
35		Non-Fuel Energy - Off-Peak (¢ per kWh)				
36		SST-1(D1)	0.751	0.751	0.000	0.0%
37		SST-1(D2)	0.751	0.751	0.000	0.0%
38		SST-1(D3)	0.751	0.751	0.000	0.0%
39		SST-1(T)	0.748	0.748	0.000	0.0%
40						
41						
42						

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1	ISST-1	Interruptible Standby and Supplemental Service				
2		Customer Charge				
3		Distribution	$448.24	$448.04	($0.20)	0.0%
4		Transmission	$1,900.79	$1,899.93	($0.86)	0.0%
5						
6		Distribution Demand				
7		Distribution	$3.16	$3.16	$0.00	0.0%
8		Transmission	N/A	N/A	N/A	N/A
9						
10		Reservation Demand-Interruptible				
11		Distribution	$0.27	$0.27	$0.00	0.0%
12		Transmission	$0.31	$0.31	$0.00	0.0%
13						
14		Reservation Demand-Firm				
15		Distribution	$1.56	$1.56	$0.00	0.0%
16		Transmission	$1.42	$1.42	$0.00	0.0%
17						
18		Supplemental Service				
19		Demand	Otherwise Applicable Rate			
20		Energy	Otherwise Applicable Rate			
21						
22		Daily Demand (On-Peak) Firm Standby				
23		Distribution	$0.75	$0.75	$0.00	0.0%
24		Transmission	$0.45	$0.45	$0.00	0.0%
25						
26		Daily Demand (On-Peak) Interruptible Standby				
27		Distribution	$0.13	$0.13	$0.00	0.0%
28		Transmission	$0.12	$0.12	$0.00	0.0%
29						
30		Non-Fuel Energy - On-Peak (¢ per kWh)				
31		Distribution	0.751	0.751	0.000	0.0%
32		Transmission	0.748	0.748	0.000	0.0%
33		Non-Fuel Energy - Off-Peak (¢ per kWh)				
34		Distribution	0.751	0.751	0.000	0.0%
35		Transmission	0.748	0.748	0.000	0.0%
36						
37		Excess "Firm Standby Demand"				
38		¤ Up to prior 60 months of service	Difference between reservation charge for			
39			firm and interruptible standby demand			
40			times excess demand			
41						
42		¤ Penalty Charge per kW for each month of rebilling	$1.13	$1.13	$0.00	0.0%

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1	TR	Transformation Rider				
2		Transformer Credit				
3		(per kW of Billing Demand)	($0.15)	($0.15)	$0.00	0.0%
4						
5						
6	GSCU-1	General Service constant Usage				
7		Customer Charge:	$14.76	$14.75	($0.01)	-0.1%
8						
9		Non-Fuel Energy Charges:				
10		Base Energy Charge*	3.705	3.703	(0.002)	-0.1%
11		* The fuel and non-fuel energy charges will be assessed on the Constant Usage kWh				
12						
13						
14	HLFT-1	High Load Factor - Time of Use				
15		Customer Charge:				
16		21 - 499 kW:	$26.32	$26.31	($0.01)	0.0%
17		500 - 1,999 kW	$78.91	$78.87	($0.04)	-0.1%
18		2,000 kW or greater	$236.55	$236.44	($0.11)	0.0%
19						
20		Demand Charges:				
21		On-peak Demand Charge:				
22		21 - 499 kW:	$11.68	$11.67	($0.01)	-0.1%
23		500 - 1,999 kW	$12.73	$12.72	($0.01)	-0.1%
24		2,000 kW or greater	$12.82	$12.81	($0.01)	-0.1%
25						
26		Maximum Demand Charge:				
27		21 - 499 kW:	$2.42	$2.42	$0.00	0.0%
28		500 - 1,999 kW	$2.73	$2.73	$0.00	0.0%
29		2,000 kW or greater	$2.72	$2.72	$0.00	0.0%
30						
31		Non-Fuel Energy Charges: (¢ per kWh)				
32		On-Peak Period				
33		21 - 499 kW:	1.909	1.908	(0.001)	-0.1%
34		500 - 1,999 kW	1.127	1.126	(0.001)	-0.1%
35		2,000 kW or greater	1.001	1.001	0.000	0.0%
36						
37						
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	HLFT-1	High Load Factor - Time of Use (continued)				
2		Off-Peak Period				
3		21 - 499 kW:	1.191	1.190	(0.001)	-0.1%
4		500 - 1,999 kW	1.076	1.076	0.000	0.0%
5		2,000 kW or greater	0.993	0.993	0.000	0.0%
6						
7						
8	SDTR	Seasonal Demand – Time of Use Rider				
9		Option A				
10		Customer Charge:				
11		21 - 499 kW:	$26.32	$26.31	($0.01)	0.0%
12		500 - 1,999 kW	$78.91	$78.87	($0.04)	-0.1%
13		2,000 kW or greater	$236.55	$236.44	($0.11)	0.0%
14						
15		Demand Charges:				
16		Seasonal On-peak Demand:				
17		21 - 499 kW:	$10.95	$10.95	$0.00	0.0%
18		500 - 1,999 kW	$12.52	$12.51	($0.01)	-0.1%
19		2,000 kW or greater	$13.11	$13.10	($0.01)	-0.1%
20						
21		Non-seasonal Demand Max Demand:				
22		21 - 499 kW:	$9.47	$9.47	$0.00	0.0%
23		500 - 1,999 kW	$11.89	$11.88	($0.01)	-0.1%
24		2,000 kW or greater	$12.38	$12.37	($0.01)	-0.1%
25						
26		Energy Charges (¢ per kWh):				
27		Seasonal On-peak Energy:				
28		21 - 499 kW:	8.775	8.771	(0.004)	0.0%
29		500 - 1,999 kW	6.203	6.200	(0.003)	0.0%
30		2,000 kW or greater	4.921	4.919	(0.002)	0.0%
31						
32		Seasonal Off-peak Energy:				
33		21 - 499 kW:	1.583	1.582	(0.001)	-0.1%
34		500 - 1,999 kW	1.258	1.257	(0.001)	-0.1%
35		2,000 kW or greater	1.229	1.228	(0.001)	-0.1%
36						
37		Non-seasonal Energy				
38		21 - 499 kW:	2.207	2.206	(0.001)	0.0%
39		500 - 1,999 kW	1.743	1.742	(0.001)	-0.1%
40		2,000 kW or greater	1.569	1.568	(0.001)	-0.1%
41						
42						

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1	SDTR	Seasonal Demand – Time of Use Rider (continued)				
2		Option B				
3		Customer Charge:				
4		21 - 499 kW:	$26.32	$26.31	($0.01)	0.0%
5		500 - 1,999 kW	$78.91	$78.87	($0.04)	-0.1%
6		2,000 kW or greater	$236.55	$236.44	($0.11)	0.0%
7						
8		Demand Charges:				
9		Seasonal On-peak Demand:				
10		21 - 499 kW:	$10.95	$10.95	$0.00	0.0%
11		500 - 1,999 kW	$12.52	$12.51	($0.01)	-0.1%
12		2,000 kW or greater	$13.11	$13.10	($0.01)	-0.1%
13						
14		Non-seasonal On-peak Demand:				
15		21 - 499 kW:	$9.47	$9.47	$0.00	0.0%
16		500 - 1,999 kW	$11.89	$11.88	($0.01)	-0.1%
17		2,000 kW or greater	$12.38	$12.37	($0.01)	-0.1%
18						
19		Energy Charges (¢ per kWh):				
20		Seasonal On-peak Energy:				
21		21 - 499 kW:	8.775	8.771	(0.004)	0.0%
22		500 - 1,999 kW	6.203	6.200	(0.003)	0.0%
23		2,000 kW or greater	4.921	4.919	(0.002)	0.0%
24						
25		Seasonal Off-peak Energy:				
26		21 - 499 kW:	1.583	1.582	(0.001)	-0.1%
27		500 - 1,999 kW	1.258	1.257	(0.001)	-0.1%
28		2,000 kW or greater	1.229	1.228	(0.001)	-0.1%
29						
30		Non-seasonal On-peak Energy:				
31		21 - 499 kW:	5.014	5.012	(0.002)	0.0%
32		500 - 1,999 kW	3.713	3.711	(0.002)	-0.1%
33		2,000 kW or greater	3.388	3.386	(0.002)	-0.1%
34						
35		Non-seasonal Off-peak Energy:				
36		21 - 499 kW:	1.583	1.582	(0.001)	-0.1%
37		500 - 1,999 kW	1.258	1.257	(0.001)	-0.1%
38		2,000 kW or greater	1.229	1.228	(0.001)	-0.1%
39						
40						
41						
42						

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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	NSMR	Non-Standard Meter Rate					
2							
3		Enrollment Fee					
4		GS-1		$89.00	$89.00	$0.00	0.0%
5		GSD-1		$89.00	$89.00	$0.00	0.0%
6		RS-1		$89.00	$89.00	$0.00	0.0%
7							
8		Monthly Surcharge					
9		GS-1		$13.00	$13.00	$0.00	0.0%
10		GSD-1		$13.00	$13.00	$0.00	0.0%
11		RS-1		$13.00	$13.00	$0.00	0.0%
12							
13							
14	LT-1	LED Lighting Pilot					
15		LED Fixtures					
16		Fixture Tier	Energy Tier				
17		1	A	$1.50	$1.50	$0.00	0.0%
18		1	B	$1.70	$1.70	$0.00	0.0%
19		1	C	$1.90	$1.90	$0.00	0.0%
20		1	D	$2.10	$2.10	$0.00	0.0%
21		1	E	$2.30	$2.30	$0.00	0.0%
22		1	F	$2.50	$2.50	$0.00	0.0%
23		1	G	$2.70	$2.70	$0.00	0.0%
24		1	H	$2.90	$2.90	$0.00	0.0%
25		1	I	$3.10	$3.10	$0.00	0.0%
26		1	J	$3.30	$3.30	$0.00	0.0%
27		1	K	$3.50	$3.50	$0.00	0.0%
28		1	L	$3.70	$3.70	$0.00	0.0%
29		1	M	$3.90	$3.90	$0.00	0.0%
30		1	N	$4.10	$4.10	$0.00	0.0%
31		1	O	$4.30	$4.30	$0.00	0.0%
32		1	P	$4.50	$4.50	$0.00	0.0%
33		1	Q	$4.70	$4.70	$0.00	0.0%
34		1	R	$4.90	$4.90	$0.00	0.0%
35		1	S	$5.10	$5.10	$0.00	0.0%
36		1	T	$5.30	$5.30	$0.00	0.0%
37		2	A	$4.50	$4.50	$0.00	0.0%
38		2	B	$4.70	$4.70	$0.00	0.0%
39		2	C	$4.90	$4.90	$0.00	0.0%
40		2	D	$5.10	$5.10	$0.00	0.0%
41		2	E	$5.30	$5.30	$0.00	0.0%
42		2	F	$5.50	$5.50	$0.00	0.0%

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	LT-1	LED Lighting Pilot (continued)					
2		2	G	$5.70	$5.70	$0.00	0.0%
3		2	H	$5.90	$5.90	$0.00	0.0%
4		2	I	$6.10	$6.10	$0.00	0.0%
5		2	J	$6.30	$6.30	$0.00	0.0%
6		2	K	$6.50	$6.50	$0.00	0.0%
7		2	L	$6.70	$6.70	$0.00	0.0%
8		2	M	$6.90	$6.90	$0.00	0.0%
9		2	N	$7.10	$7.10	$0.00	0.0%
10		2	O	$7.30	$7.30	$0.00	0.0%
11		2	P	$7.50	$7.50	$0.00	0.0%
12		2	Q	$7.70	$7.70	$0.00	0.0%
13		2	R	$7.90	$7.90	$0.00	0.0%
14		2	S	$8.10	$8.10	$0.00	0.0%
15		2	T	$8.30	$8.30	$0.00	0.0%
16		3	A	$7.50	$7.50	$0.00	0.0%
17		3	B	$7.70	$7.70	$0.00	0.0%
18		3	C	$7.90	$7.90	$0.00	0.0%
19		3	D	$8.10	$8.10	$0.00	0.0%
20		3	E	$8.30	$8.30	$0.00	0.0%
21		3	F	$8.50	$8.50	$0.00	0.0%
22		3	G	$8.70	$8.70	$0.00	0.0%
23		3	H	$8.90	$8.90	$0.00	0.0%
24		3	I	$9.10	$9.10	$0.00	0.0%
25		3	J	$9.30	$9.30	$0.00	0.0%
26		3	K	$9.50	$9.50	$0.00	0.0%
27		3	L	$9.70	$9.70	$0.00	0.0%
28		3	M	$9.90	$9.90	$0.00	0.0%
29		3	N	$10.10	$10.10	$0.00	0.0%
30		3	O	$10.30	$10.30	$0.00	0.0%
31		3	P	$10.50	$10.50	$0.00	0.0%
32		3	Q	$10.70	$10.70	$0.00	0.0%
33		3	R	$10.90	$10.90	$0.00	0.0%
34		3	S	$11.10	$11.10	$0.00	0.0%
35		3	T	$11.30	$11.30	$0.00	0.0%
36		4	A	$10.50	$10.50	$0.00	0.0%
37		4	B	$10.70	$10.70	$0.00	0.0%
38		4	C	$10.90	$10.90	$0.00	0.0%
39		4	D	$11.10	$11.10	$0.00	0.0%
40		4	E	$11.30	$11.30	$0.00	0.0%
41		4	F	$11.50	$11.50	$0.00	0.0%
42		4	G	$11.70	$11.70	$0.00	0.0%

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	LT-1	LED Lighting Pilot (continued)					
2		4	H	$11.90	$11.90	$0.00	0.0%
3		4	I	$12.10	$12.10	$0.00	0.0%
4		4	J	$12.30	$12.30	$0.00	0.0%
5		4	K	$12.50	$12.50	$0.00	0.0%
6		4	L	$12.70	$12.70	$0.00	0.0%
7		4	M	$12.90	$12.90	$0.00	0.0%
8		4	N	$13.10	$13.10	$0.00	0.0%
9		4	O	$13.30	$13.30	$0.00	0.0%
10		4	P	$13.50	$13.50	$0.00	0.0%
11		4	Q	$13.70	$13.70	$0.00	0.0%
12		4	R	$13.90	$13.90	$0.00	0.0%
13		4	S	$14.10	$14.10	$0.00	0.0%
14		4	T	$14.30	$14.30	$0.00	0.0%
15		5	A	$13.50	$13.50	$0.00	0.0%
16		5	B	$13.70	$13.70	$0.00	0.0%
17		5	C	$13.90	$13.90	$0.00	0.0%
18		5	D	$14.10	$14.10	$0.00	0.0%
19		5	E	$14.30	$14.30	$0.00	0.0%
20		5	F	$14.50	$14.50	$0.00	0.0%
21		5	G	$14.70	$14.70	$0.00	0.0%
22		5	H	$14.90	$14.90	$0.00	0.0%
23		5	I	$15.10	$15.10	$0.00	0.0%
24		5	J	$15.30	$15.30	$0.00	0.0%
25		5	K	$15.50	$15.50	$0.00	0.0%
26		5	L	$15.70	$15.70	$0.00	0.0%
27		5	M	$15.90	$15.90	$0.00	0.0%
28		5	N	$16.10	$16.10	$0.00	0.0%
29		5	O	$16.30	$16.30	$0.00	0.0%
30		5	P	$16.50	$16.50	$0.00	0.0%
31		5	Q	$16.70	$16.70	$0.00	0.0%
32		5	R	$16.90	$16.90	$0.00	0.0%
33		5	S	$17.10	$17.10	$0.00	0.0%
34		5	T	$17.30	$17.30	$0.00	0.0%
35		6	A	$16.50	$16.50	$0.00	0.0%
36		6	B	$16.70	$16.70	$0.00	0.0%
37		6	C	$16.90	$16.90	$0.00	0.0%
38		6	D	$17.10	$17.10	$0.00	0.0%
39		6	E	$17.30	$17.30	$0.00	0.0%
40		6	F	$17.50	$17.50	$0.00	0.0%
41		6	G	$17.70	$17.70	$0.00	0.0%
42		6	H	$17.90	$17.90	$0.00	0.0%

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
	LT-1	LED Lighting Pilot (continued)					
1		6	I	$18.10	$18.10	$0.00	0.0%
2		6	J	$18.30	$18.30	$0.00	0.0%
3		6	K	$18.50	$18.50	$0.00	0.0%
4		6	L	$18.70	$18.70	$0.00	0.0%
5		6	M	$18.90	$18.90	$0.00	0.0%
6		6	N	$19.10	$19.10	$0.00	0.0%
7		6	O	$19.30	$19.30	$0.00	0.0%
8		6	P	$19.50	$19.50	$0.00	0.0%
9		6	Q	$19.70	$19.70	$0.00	0.0%
10		6	R	$19.90	$19.90	$0.00	0.0%
11		6	S	$20.10	$20.10	$0.00	0.0%
12		6	T	$20.30	$20.30	$0.00	0.0%
13		7	A	$19.50	$19.50	$0.00	0.0%
14		7	B	$19.70	$19.70	$0.00	0.0%
15		7	C	$19.90	$19.90	$0.00	0.0%
16		7	D	$20.10	$20.10	$0.00	0.0%
17		7	E	$20.30	$20.30	$0.00	0.0%
18		7	F	$20.50	$20.50	$0.00	0.0%
19		7	G	$20.70	$20.70	$0.00	0.0%
20		7	H	$20.90	$20.90	$0.00	0.0%
21		7	I	$21.10	$21.10	$0.00	0.0%
22		7	J	$21.30	$21.30	$0.00	0.0%
23		7	K	$21.50	$21.50	$0.00	0.0%
24		7	L	$21.70	$21.70	$0.00	0.0%
25		7	M	$21.90	$21.90	$0.00	0.0%
26		7	N	$22.10	$22.10	$0.00	0.0%
27		7	O	$22.30	$22.30	$0.00	0.0%
28		7	P	$22.50	$22.50	$0.00	0.0%
29		7	Q	$22.70	$22.70	$0.00	0.0%
30		7	R	$22.90	$22.90	$0.00	0.0%
31		7	S	$23.10	$23.10	$0.00	0.0%
32		7	T	$23.30	$23.30	$0.00	0.0%
33		8	A	$22.50	$22.50	$0.00	0.0%
34		8	B	$22.70	$22.70	$0.00	0.0%
35		8	C	$22.90	$22.90	$0.00	0.0%
36		8	D	$23.10	$23.10	$0.00	0.0%
37		8	E	$23.30	$23.30	$0.00	0.0%
38		8	F	$23.50	$23.50	$0.00	0.0%
39		8	G	$23.70	$23.70	$0.00	0.0%
40		8	H	$23.90	$23.90	$0.00	0.0%
41		8	I	$24.10	$24.10	$0.00	0.0%
42		8	J	$24.30	$24.30	$0.00	0.0%

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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
	LT-1	LED Lighting Pilot (continued)					
1		8	K	$24.50	$24.50	$0.00	0.0%
2		8	L	$24.70	$24.70	$0.00	0.0%
3		8	M	$24.90	$24.90	$0.00	0.0%
4		8	N	$25.10	$25.10	$0.00	0.0%
5		8	O	$25.30	$25.30	$0.00	0.0%
6		8	P	$25.50	$25.50	$0.00	0.0%
7		8	Q	$25.70	$25.70	$0.00	0.0%
8		8	R	$25.90	$25.90	$0.00	0.0%
9		8	S	$26.10	$26.10	$0.00	0.0%
10		8	T	$26.30	$26.30	$0.00	0.0%
11		9	A	$25.50	$25.50	$0.00	0.0%
12		9	B	$25.70	$25.70	$0.00	0.0%
13		9	C	$25.90	$25.90	$0.00	0.0%
14		9	D	$26.10	$26.10	$0.00	0.0%
15		9	E	$26.30	$26.30	$0.00	0.0%
16		9	F	$26.50	$26.50	$0.00	0.0%
17		9	G	$26.70	$26.70	$0.00	0.0%
18		9	H	$26.90	$26.90	$0.00	0.0%
19		9	I	$27.10	$27.10	$0.00	0.0%
20		9	J	$27.30	$27.30	$0.00	0.0%
21		9	K	$27.50	$27.50	$0.00	0.0%
22		9	L	$27.70	$27.70	$0.00	0.0%
23		9	M	$27.90	$27.90	$0.00	0.0%
24		9	N	$28.10	$28.10	$0.00	0.0%
25		9	O	$28.30	$28.30	$0.00	0.0%
26		9	P	$28.50	$28.50	$0.00	0.0%
27		9	Q	$28.70	$28.70	$0.00	0.0%
28		9	R	$28.90	$28.90	$0.00	0.0%
29		9	S	$29.10	$29.10	$0.00	0.0%
30		9	T	$29.30	$29.30	$0.00	0.0%
31		10	A	$28.50	$28.50	$0.00	0.0%
32		10	B	$28.70	$28.70	$0.00	0.0%
33		10	C	$28.90	$28.90	$0.00	0.0%
34		10	D	$29.10	$29.10	$0.00	0.0%
35		10	E	$29.30	$29.30	$0.00	0.0%
36		10	F	$29.50	$29.50	$0.00	0.0%
37		10	G	$29.70	$29.70	$0.00	0.0%
38		10	H	$29.90	$29.90	$0.00	0.0%
39		10	I	$30.10	$30.10	$0.00	0.0%
40		10	J	$30.30	$30.30	$0.00	0.0%
41		10	K	$30.50	$30.50	$0.00	0.0%
42		10	L	$30.70	$30.70	$0.00	0.0%

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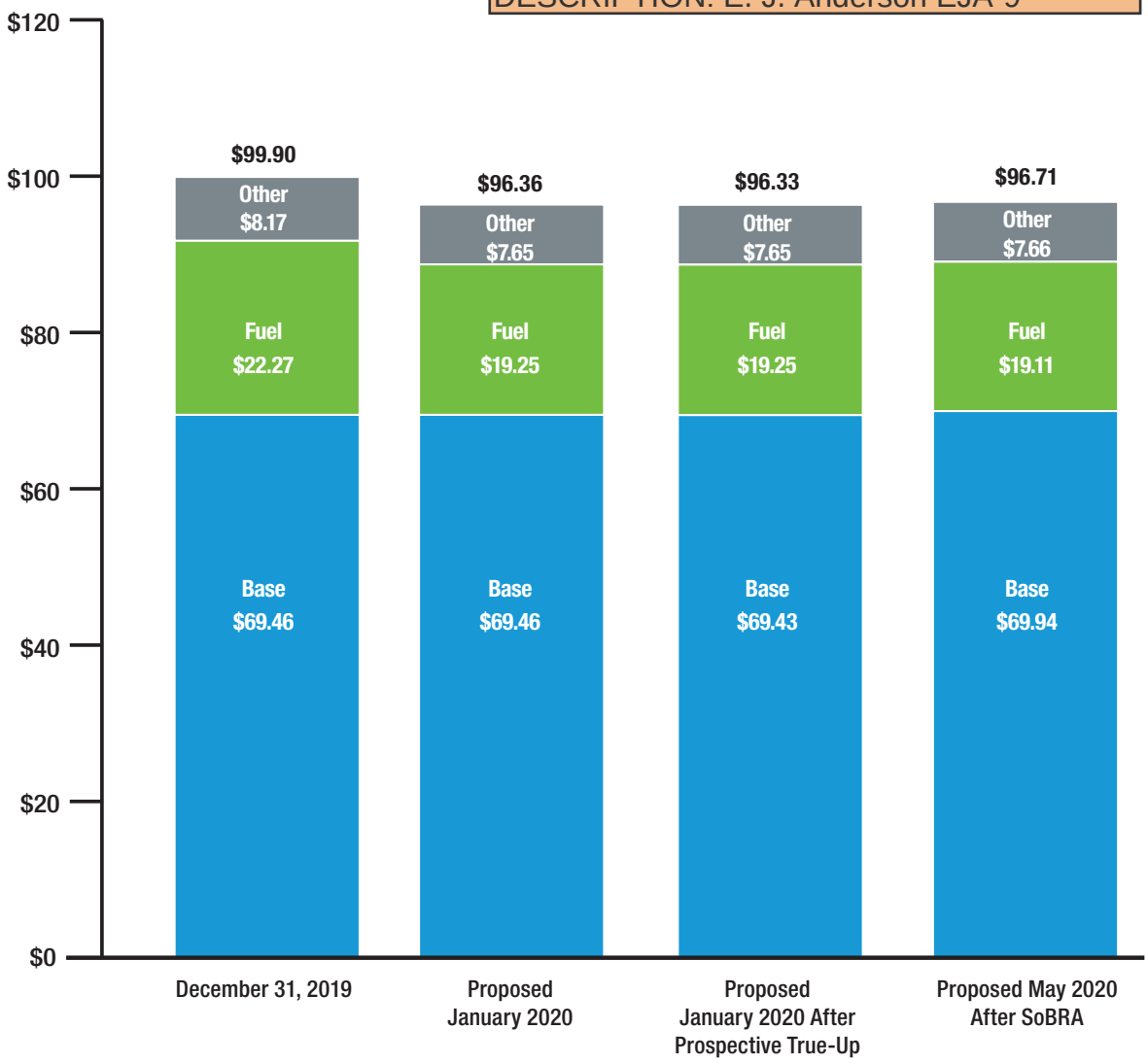
LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) APRIL 1, 2019 APPROVED RATE*	(4) JANUARY 1, 2020 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
	LT-1	LED Lighting Pilot (continued)				
1		10 M	$30.90	$30.90	$0.00	0.0%
2		10 N	$31.10	$31.10	$0.00	0.0%
3		10 O	$31.30	$31.30	$0.00	0.0%
4		10 P	$31.50	$31.50	$0.00	0.0%
5		10 Q	$31.70	$31.70	$0.00	0.0%
6		10 R	$31.90	$31.90	$0.00	0.0%
7		10 S	$32.10	$32.10	$0.00	0.0%
8		10 T	$32.30	$32.30	$0.00	0.0%
9						
10						
11		Energy Tier Charges				
12		Energy Tier				
13		A	$0.00	$0.00	$0.00	0.0%
14		B	$0.20	$0.20	$0.00	0.0%
15		C	$0.40	$0.40	$0.00	0.0%
16		D	$0.60	$0.60	$0.00	0.0%
17		E	$0.80	$0.80	$0.00	0.0%
18		F	$1.00	$1.00	$0.00	0.0%
19		G	$1.20	$1.20	$0.00	0.0%
20		H	$1.40	$1.40	$0.00	0.0%
21		I	$1.60	$1.60	$0.00	0.0%
22		J	$1.80	$1.80	$0.00	0.0%
23		K	$2.00	$2.00	$0.00	0.0%
24		L	$2.20	$2.20	$0.00	0.0%
25		M	$2.40	$2.40	$0.00	0.0%
26		N	$2.60	$2.60	$0.00	0.0%
27		O	$2.80	$2.80	$0.00	0.0%
28		P	$3.00	$3.00	$0.00	0.0%
29		Q	$3.20	$3.20	$0.00	0.0%
30		R	$3.40	$3.40	$0.00	0.0%
31		S	$3.60	$3.60	$0.00	0.0%
32		T	$3.80	$3.80	$0.00	0.0%
33						
34		Non-Fuel Energy (¢ per kWh)	3.042	3.041	(0.001)	0.0%
35						
36						
37		Charges for Maintenance and Conversion Recovery:				
38		Maintenance per Fixture (FPL Owned Fixture and Pole)	$1.82	$1.82	$0.00	0.0%
39		Maintenance per Fixture for FPL Fixtures on Customer Pole	$1.27	$1.27	$0.00	0.0%
40		LED Conversion Recovery	$1.03	$1.03	$0.00	0.0%
41						
42		Charges for Other FPL-Owned Facilities:				
43		Wood pole used only for the street lighting system	$5.20	$5.20	$0.00	0.0%
44		Standard Concrete pole used only for the street lighting system	$7.11	$7.11	$0.00	0.0%
45		Round Fiberglass pole used only for the street lighting system	$8.42	$8.42	$0.00	0.0%
46		Decorative Tall Fiberglass pole used only for the street lighting system	$17.77	$17.76	($0.01)	-0.1%
47		Decorative Concrete pole used only for the street lighting system	$14.43	$14.42	($0.01)	-0.1%
48		Underground conductors (¢ per foot)	4.026	4.024	(0.002)	0.0%

* April 1, 2019 Rates approved in Docket No. 20180001-EI

Typical 1,000-kWh Residential Customer Bill Comparison

RS-1 Rate

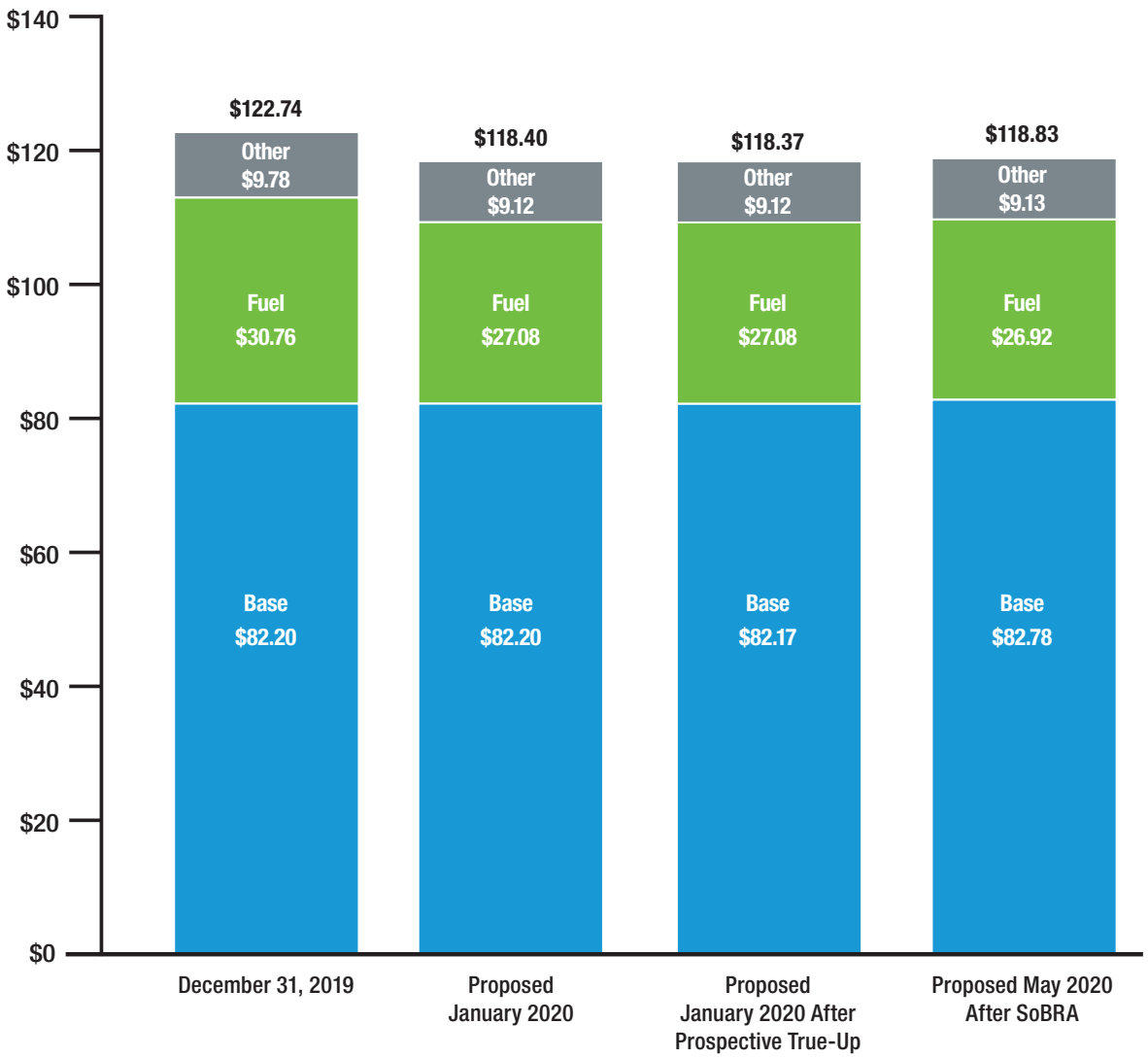
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 48
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT)
DESCRIPTION: E. J. Anderson EJA-9



The December 2019 bill reflects approved rates effective for December 2019. The 2020 bill estimates include projected 2020 rates for fuel, capacity, environmental, and conservation; proposed Prospective True-Up rate adjustments; proposed SoBRA rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

1,200-kWh Commercial Customer Bill Comparison (non-demand)

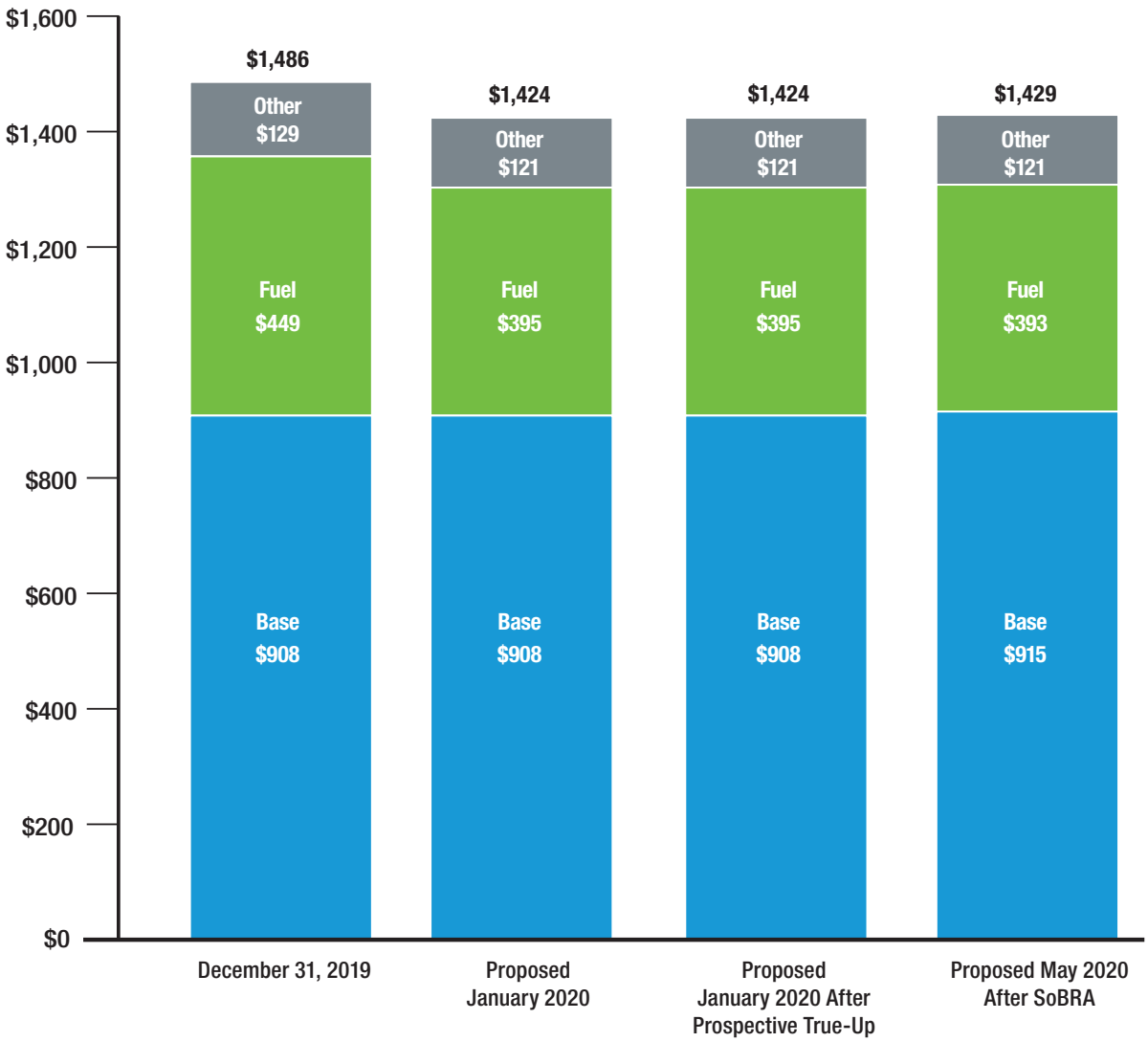
GS-1 Rate



The December 2019 bill reflects approved rates effective for December 2019. The 2020 bill estimates include projected 2020 rates for fuel, capacity, environmental, and conservation; proposed Prospective True-Up rate adjustments; proposed SoBRA rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

17,520-kWh Commercial Customer Bill Comparison

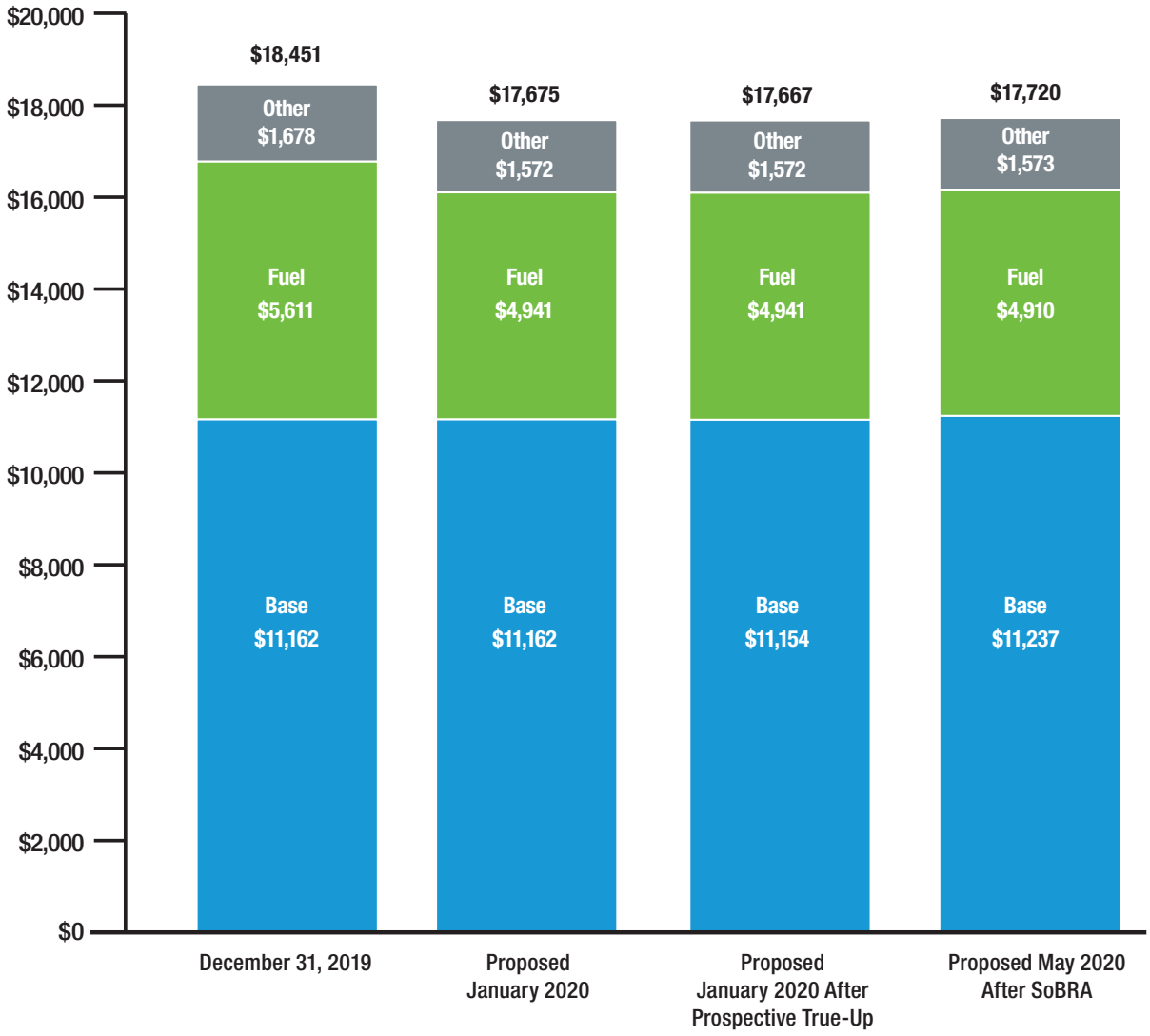
GSD-1 Rate 50 kW, 48% load factor



The December 2019 bill reflects approved rates effective for December 2019. The 2020 bill estimates include projected 2020 rates for fuel, capacity, environmental, and conservation; proposed Prospective True-Up rate adjustments; proposed SoBRA rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

219,000-kWh Commercial Customer Bill Comparison

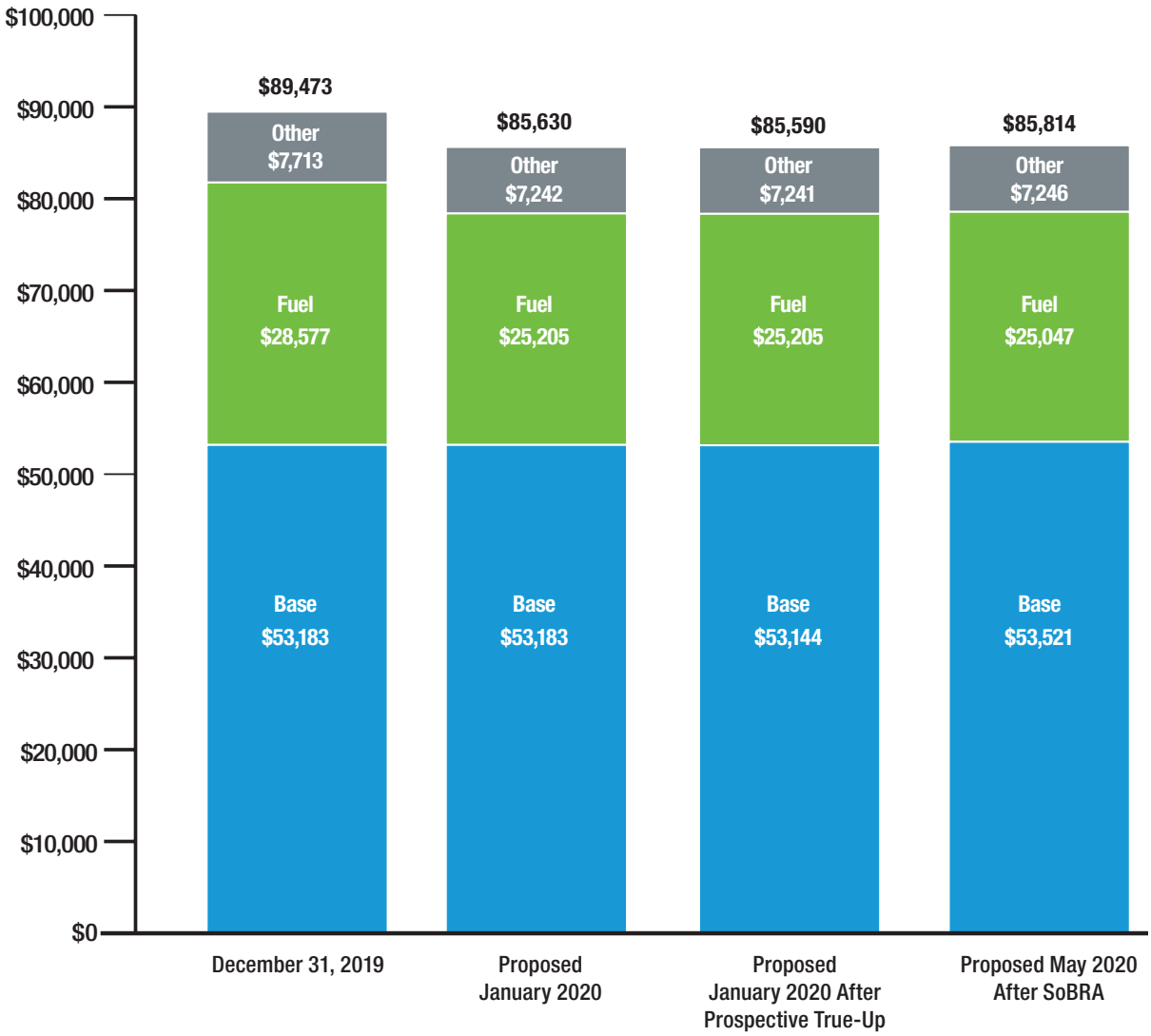
GSLD-1 Rate 600 kW, 50% load factor



The December 2019 bill reflects approved rates effective for December 2019. The 2020 bill estimates include projected 2020 rates for fuel, capacity, environmental, and conservation; proposed Prospective True-Up rate adjustments; proposed SoBRA rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

1,124,200-kWh Commercial Customer Bill Comparison

GSLD-2 Rate 2,800 kW, 55% load factor



The December 2019 bill reflects approved rates effective for December 2019. The 2020 bill estimates include projected 2020 rates for fuel, capacity, environmental, and conservation; proposed Prospective True-Up rate adjustments; proposed SoBRA rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

Schedule A

FLORIDA PUBLIC UTILITIES
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2018 THROUGH DECEMBER 2018

CONSOLIDATED ELECTRIC DIVISION

1	JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	$ 59,966,397
2	JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	62,086,197
3	ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD	2,119,800
4	ADJUSTMENTS (INCL. REVENUE REFUND TRUE-UP ADJUSTMENT)*	(1,210,173)
5	INTEREST	(145,979)
6	TRUE-UP COLLECTED	3,391,416
7	PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/17)	(5,637,395)
8	ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 3 + LINE4 + LINE5 + LINE6 + LINE7)	(1,482,331)
9	PROJECTED UNDER-RECOVERY PER PROJECTION FILED 7/27/18	(3,957,772)
10	**FINAL FUEL OVER/(UNDER) RECOVERY (LINE 8 - LINE 9)**	**$ 2,475,441**
11	FINAL FUEL OVER/(UNDER) RECOVERY (excluding the Federal Tax savings)	$ 294,198

* *Includes $2,181,243 Federal Tax Savings*

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 49
PARTY: FLORIDA PUBLIC UTILITIES COMPANY – (DIRECT)
DESCRIPTION: Curtis D. Young CDY-1

Exhibit No._____
DOCKET NO. 190001-EI
Florida Public Utilities Company
(CDY - 1)
Page 1 of 3

Schedule E-1b
Exhibit No.
DOCKET NO. 190001-EI
Florida Public Utilities Company
'(CDY - 1)
Page 2 of 3

FLORIDA PUBLIC UTILITIES COMPANY

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

CONSOLIDATED

	ACTUAL Jan 2018	ACTUAL Feb 2018	ACTUAL Mar 2018	ACTUAL Apr 2018	ACTUAL May 2018	ACTUAL Jun 2018	Estimated Jul 2018	Estimated Aug 2018	Estimated Sep 2018	Estimated Oct 2018	Estimated Nov 2018	Estimated Dec 2018	Total
Total System Sales - KWH	62,776,781	49,056,832	41,956,289	42,986,962	43,497,274	59,593,624	67,713,270	68,178,975	66,804,826	57,947,611	53,757,461	47,002,405	661,272,310
West Rock Purchases - KWH	1,009,032	580,000	560,000	360,000	610,000	700,000	1,170,000	460,000	740,000	1,260,000	370,000	640,000	8,459,032
Rayonier Purchases - KWH - On Peak	535,944	385,225	522,115	379,519	467,506	264,582	337,310	306,990	530,600	276,670	193,290	72,010	4,271,761
Rayonier Purchases - KWH - Off Peak	508,395	774,251	796,212	1,041,888	1,029,865	699,063	552,690	503,010	469,400	453,330	316,710	117,990	7,262,804
Eight Flags Purchases - KWH - KWH	15,670,987	13,098,447	16,366,190	15,128,267	14,912,893	13,867,929	11,200,000	10,900,000	12,400,000	13,800,000	12,800,000	14,800,000	164,944,713
FPL Purchases - KWH	25,761,545	7,528,045	7,334,909	6,137,056	11,582,193	19,890,816	23,304,383	23,937,375	15,543,481	13,822,292	13,192,323	8,327,932	176,362,350
Gulf Purchases - KWH	31,143,370	19,872,269	21,790,729	20,397,536	26,256,757	29,217,222	31,957,706	32,302,774	31,278,494	25,184,059	20,812,278	22,028,426	312,241,619
Generation Demand - KW - FPL	105,473	46,510	40,841	30,960	43,088	67,143	53,500	53,700	56,400	45,100	31,100	35,400	609,215
Generation Demand - KW - Gulf	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	1,092,000
Transmission Demand - KW - FPL	88,796	30,551	41,759	31,553	43,088	72,984	53,500	53,700	56,400	45,100	31,100	35,400	583,931
Transmission Demand - KW - Southern	54,339	55,525	56,266	56,392	55,968	54,989	55,000	55,000	55,000	55,000	55,000	55,000	663,479
Purchased Power Rates:													
West Rock Fuel Costs - $/KWH	0.04612	0.00590	0.03166	0.03114	0.03652	0.03632	0.03785	0.03785	0.03785	0.03785	0.03785	0.03785	
Rayonier Energy Charge - On Peak - $/KWH	0.05171	0.05171	0.05171	0.06377	0.04004	0.04004	0.04265	0.04265	0.04265	0.04265	0.04265	0.04265	
Rayonier Energy Charge - Off Peak - $/KWH	0.03196	0.03745	0.03745	0.03824	0.04221	0.04221	0.04265	0.04265	0.04265	0.04265	0.04265	0.04265	
Eight Flags Charge - $/KWH	0.07831	0.08978	0.07572	0.07712	0.07956	0.08197	0.07900	0.07900	0.07900	0.07900	0.07900	0.07900	
Base Fuel Costs - $/KWH FPL	0.04733	(0.01491)	0.02711	0.02735	0.03141	0.03474	0.03527	0.03471	0.05019	0.03634	0.03276	0.02933	
Base Fuel Costs - $/KWH GULF 0.974	0.05561	0.05561	0.05561	0.05561	0.05561	0.05561	0.05561	0.05561	0.05561	0.05561	0.05561	0.05561	
Energy Charge - $/KWH - FPL	0.00160	0.00076	0.00219	0.00224	0.00195	0.00169	0.00165	0.00164	0.00191	0.00203	0.00186	0.00219	
Demand and Non-Fuel:													
Demand Charge - $/KW - FPL	6.14	4.53	7.24	7.81	7.15	6.54	6.82	6.81	6.75	7.07	7.80	7.52	
Demand Charge - $/KW - Gulf	12.25	12.25	12.25	12.25	12.25	12.25	12.25	12.25	12.25	12.25	12.25	12.25	
Distribution Facility Charge	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	
Transmission Charge $/KW - FPL	1.85	1.72	1.80	1.71	1.85	1.92	1.85	1.85	1.85	1.85	1.85	1.85	
Transmission Charge $/KW - Southern	3.01632	3.01632	3.47361	3.01631	3.00966	2.10084	3.02	3.02	3.02	3.02	3.02	3.02	
Purchased Power Costs:													
RockTenn Fuel Costs	46,561	3,423	37,114	11,210	22,279	25,425	44,285	17,411	28,009	47,691	14,005	24,224	321,636
Rayonier Standby Costs	43,006	48,916	56,817	64,044	62,190	40,101	37,958	34,546	42,650	31,135	21,752	8,103	491,218
Eight Flags	1,227,132	1,175,964	1,239,239	1,166,711	1,186,434	1,136,759	884,800	861,100	979,600	1,090,200	1,011,200	1,169,200	13,128,339
Gulf Base Fuel Costs	1,778,114	1,134,596	1,244,130	1,164,586	1,499,115	1,668,141	1,824,608	1,844,309	1,785,829	1,437,870	1,188,266	1,257,701	17,827,265
FPL Base Fuel Costs	1,397,040	(112,219)	198,814	167,818	363,835	691,040	822,039	830,928	780,120	502,262	432,223	244,277	6,318,177
FPL Fuel Adjustment	98,990	5,738	16,029	13,746	22,591	33,634	38,447	39,144	29,658	28,017	24,572	18,223	368,789
Subtotal Fuel Costs	4,590,843	2,256,418	2,792,143	2,588,115	3,156,444	3,595,100	3,652,137	3,627,438	3,645,866	3,137,175	2,692,018	2,721,728	38,455,424
Demand and Non-Fuel Cost: Demand Capacity Charge	1,760,869	1,325,216	1,410,551	1,356,701	1,422,800	1,553,899	1,479,545	1,480,635	1,495,350	1,433,765	1,357,465	1,380,900	17,457,696
Distr. Fac. Charge	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	1,011,034
FERC & Meter Reading	4,926	5,407	4,454	4,616	4,499	4,994	5,244	5,475	5,505	5,418	4,903	4,534	59,975
Transmission Charge	328,539	219,994	270,441	224,163	248,334	255,346	265,091	265,462	270,468	249,517	223,560	231,532	3,052,447
Subtotal Demand & Non-Fuel Costs	2,178,587	1,634,870	1,769,699	1,669,733	1,759,886	1,898,492	1,834,133	1,835,825	1,855,576	1,772,953	1,670,181	1,701,219	21,581,152
Total System Purchased Power Costs	6,769,430	3,891,288	4,561,841	4,257,848	4,916,330	5,493,592	5,486,270	5,463,263	5,501,442	4,910,128	4,362,199	4,422,947	60,036,576
Less Direct Billing To GSLD1 Class: Demand	13,932	4,465	34,314	2,611	3,917	68,011	24,140	24,140	24,140	24,140	24,140	24,140	272,091
Commodity	60,921	57,130	65,160	42,272	31,609	85,941	86,246	99,680	89,905	184,472	166,306	99,034	1,068,677
Net Purchased Power Costs	6,694,577	3,829,693	4,462,367	4,212,964	4,880,804	5,339,640	5,375,884	5,339,442	5,387,397	4,701,516	4,171,753	4,299,773	58,695,808
Special Costs*	73,284	44,138	139,450	16,771	55,856	13,357	17,850	17,850	19,300	17,850	17,850	20,300	453,856
Total Costs and Charges	6,767,861	3,873,831	4,601,816	4,229,735	4,936,659	5,352,997	5,393,734	5,357,292	5,406,697	4,719,366	4,189,603	4,320,073	59,149,664
Sales Revenues - Fuel Adjustment Revenues:													
RS< 0.09313	1,884,620	1,675,526	1,435,111	1,492,599	1,477,836	1,787,458	1,914,931	1,899,558	1,860,686	1,657,504	1,473,484	1,519,143	20,078,456
RS> 0.10562	1,639,187	731,720	258,434	333,449	368,168	945,445	1,384,094	1,267,104	1,159,685	694,428	331,334	436,648	9,549,696
GS 0.09384	490,344	408,535	342,864	365,685	376,598	501,898	627,712	629,443	607,580	522,521	443,463	425,850	5,742,493
GSD 0.09023	1,215,788	1,084,570	997,131	1,068,366	1,105,680	1,403,630	1,593,051	1,593,866	1,601,379	1,368,142	1,227,966	1,146,157	15,405,726
GSLD 0.08763	554,427	492,006	514,758	554,162	562,936	672,100	725,212	757,217	773,249	705,071	686,072	629,256	7,626,466
LS 0.07131	44,031	45,283	45,630	45,393	46,229	45,519	44,673	44,721	44,861	44,773	44,863	44,892	540,867
Unbilled Fuel Revenues	421,846	(739,091)	139,967	(124,925)	280,343	266,305	(100,000)	200,000	150,000	(250,000)	100,000	200,000	544,445
Total Fuel Revenues (Excl. GSLD1)	6,250,242	3,698,549	3,733,895	3,734,729	4,217,791	5,622,355	6,189,673	6,391,909	6,197,440	4,742,439	4,307,182	4,401,946	59,488,149
GSLD1 Fuel .17197	74,853	61,595	99,475	44,884	35,526	153,952	110,386	123,820	114,045	208,612	190,446	123,174	1,340,768
Non-Fuel Revenues	2,758,503	2,284,245	1,950,784	2,035,836	1,961,351	2,519,591	3,167,224	2,975,578	2,546,304	1,941,858	2,369,448	2,711,799	29,222,520
Total Sales Revenue	9,083,598	6,044,389	5,784,153	5,815,449	6,214,668	8,295,897	9,467,284	9,491,307	8,857,789	6,892,909	6,867,075	7,236,919	90,051,437
KWH Sales: RS<	20,233,969	17,991,470	15,409,738	16,027,079	15,868,685	19,193,450	20,561,261	20,396,199	19,978,814	17,797,186	15,821,295	16,311,554	215,590,700
RS>	15,518,575	6,927,589	2,446,688	3,156,938	3,485,645	8,951,039	13,103,983	11,996,373	10,979,372	6,574,534	3,136,921	4,133,990	90,411,647
GS	5,224,765	4,353,415	3,653,612	3,896,794	4,013,083	5,348,305	6,689,000	6,707,441	6,474,470	5,568,070	4,725,608	4,537,928	61,192,491
GSD	13,476,402	12,034,455	11,061,007	11,855,377	12,268,223	15,571,594	17,656,413	17,665,446	17,748,724	15,163,665	13,610,036	12,703,309	170,814,651
GSLD	6,327,128	5,614,784	5,874,424	6,324,108	6,424,236	7,670,016	8,276,133	8,641,372	8,824,334	8,046,282	7,829,468	7,181,078	87,033,363
GSLD1	1,370,000	1,500,000	2,870,000	1,090,000	800,000	2,220,000	800,000	2,145,000	2,170,000	4,170,000	8,005,000	1,505,000	28,645,000
LS	625,942	635,119	640,800	636,666	637,402	639,220	626,480	627,144	629,112	627,874	629,133	629,546	7,584,438
Total KWH Sales	62,776,781	49,056,832	41,956,269	42,986,962	43,497,274	59,593,624	67,713,270	68,178,975	66,804,826	57,947,611	53,757,461	47,002,405	661,272,290
True-up Calculation (Excl. GSLD1):													
Fuel Revenues	6,250,242	3,698,549	3,733,895	3,734,729	4,217,791	5,622,355	6,189,673	6,391,909	6,197,440	4,742,439	4,307,182	4,401,946	59,488,149
True-up Provision - collect/(refund)	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	3,391,416
Gross Receipts Tax Refund													0
Fuel Revenue	5,967,624	3,415,931	3,451,277	3,452,111	3,935,173	5,339,737	5,907,055	6,109,291	5,914,822	4,459,821	4,024,564	4,119,328	56,096,733
Net Purchased Power and Other Fuel Costs	6,767,861	3,873,831	4,601,816	4,229,735	4,936,659	5,352,997	5,393,734	5,357,292	5,406,697	4,719,366	4,189,603	4,320,073	59,149,664
True-up Provision for the Period	(800,236)	(457,899)	(1,150,540)	(777,625)	(1,001,486)	(13,260)	513,322	751,998	508,126	(259,545)	(165,040)	(200,745)	(3,052,931)
Interest Provision for the Period	(7,347)	(8,231)	(9,946)	(11,707)	(12,677)	(13,390)	(12,555)	(11,104)	(9,654)	(9,015)	(8,917)	(8,771)	(123,314)
Beginning of Period True-up and Interest Provision	(5,637,395)	(6,162,360)	(6,345,873)	(7,223,741)	(7,730,454)	(8,462,000)	(8,206,032)	(7,422,647)	(6,399,135)	(5,618,045)	(5,603,988)	(5,495,326)	(5,637,395)
True-up Collected or (Refunded)	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	3,391,416
												1,464,452	1,464,452
End of Period, Net True-up and Int. Prov.	(6,162,360)	(6,345,873)	(7,223,741)	(7,730,454)	(8,462,000)	(8,206,032)	(7,422,647)	(6,399,135)	(5,618,045)	(5,603,988)	(5,495,326)	(3,957,772)	(3,957,772)
Beginning True-up Amount	(5,637,395)	(6,162,360)	(6,345,873)	(7,223,741)	(7,730,454)	(8,462,000)	(8,206,032)	(7,422,647)	(6,399,135)	(5,618,045)	(5,603,988)	(5,495,326)	
Ending True-up Amount Before Interest	(6,155,013)	(6,337,642)	(7,213,795)	(7,718,747)	(8,449,323)	(8,192,642)	(7,410,092)	(6,388,031)	(5,608,391)	(5,594,973)	(5,486,409)	(5,413,453)	
Total Beginning and Ending True-up	(11,792,408)	(12,500,002)	(13,559,667)	(14,942,488)	(16,179,777)	(16,654,642)	(15,616,124)	(13,810,678)	(12,007,526)	(11,213,018)	(11,090,397)	(10,908,779)	10% Rule Interest Provision: -6.59%
Average True-up Amount	(5,896,204)	(6,250,001)	(6,779,834)	(7,471,244)	(8,089,888)	(8,327,321)	(7,808,062)	(6,905,339)	(6,003,763)	(5,606,509)	(5,545,198)	(5,454,390)	
Average Annual Interest Rate	1.4950%	1.5800%	1.7600%	1.8800%	1.8800%	1.9300%	1.9300%	1.9300%	1.9300%	1.9300%	1.9300%	1.9300%	
Interest Provision	(7,347)	(8,231)	(9,946)	(11,707)	(12,677)	(13,390)	(12,555)	(11,104)	(9,654)	(9,015)	(8,917)	(8,771)	

* Includes: Consulting fees, Legal fees and Taxes on Company Use.

FLORIDA PUBLIC UTILITIES COMPANY

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

BASED ON TWELVE MONTHs ACTUAL

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

Schedule C1
Exhibit No.
DOCKET NO. 190001-EI
Florida Public Utilities Company
'(CDY - 1)
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			2018											
			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			62,776,781	49,056,832	41,956,269	42,986,962	43,497,274	59,593,624	64,827,143	62,702,595	66,269,266	56,215,041	26,240,264	84,425,020	660,547,071
WEST-ROCK Purchases - KWH			1,009,032	580,000	560,000	360,000	610,000	700,000	640,000	460,000	760,000	520,000	590,000	690,000	7,479,032
Rayonier Purchases - KWH - On Peak			535,944	385,225	522,115	379,519	467,506	264,582	247,743	333,949	405,379	350,667	201,845	139,361	4,233,855
Rayonier Purchases - KWH - Off Peak			508,395	774,251	796,212	1,041,888	1,029,865	699,063	731,031	791,203	951,728	685,160	219,470	197,078	8,425,344
Eight Flags Purchases-KWH			15,670,987	13,096,447	16,366,190	15,128,267	14,912,893	13,867,929	11,921,424	12,457,820	13,386,831	13,937,351	13,724,284	14,033,884	168,504,307
FPL Purchases - KWH			25,761,545	7,528,045	7,334,909	6,137,056	11,582,193	19,890,816	23,329,680	18,749,616	20,660,878	14,672,002	9,811,522	10,087,859	175,546,121
Gulf Purchases - KWH			31,143,370	19,872,269	21,790,729	20,397,536	26,256,757	29,217,222	30,800,653	29,707,966	29,171,885	14,746,222	20,510,945	22,909,834	296,525,388
System Billing Demand - FPL KW			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
System Billing Demand - Gulf KW			91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	1,092,000
Peak Billing Demand- Southern KW			54,339	55,525	56,266	56,392	55,968	54,989	54,797	56,555	56,935	56,413	56,649	56,066	670,894
DEMAND-KW-(network load) FPL TRANS			91,473	32,510	26,841	16,960	29,088	53,143	55,049	62,355	41,516	37,154	27,002	34,828	507,919
Purchased Power Rates:															
WestRock Fuel Costs - $/KWH			0 04612	0.00590	0.03166	0.03114	0.03652	0.03632	0.03674	0.03636	0.03622	0.03457	0.03281	0.03457	
Rayonier -Energy Charge- On Peak - $/KWH			0.05171	0.05171	0.05171	0.06377	0.04004	0.04004	0.04004	0.04004	0.06845	0.03813	0.03425	0.03425	
Rayonier- Energy Charge - Off Peak - $/KWH			0.03196	0.03745	0.03745	0.03824	0.04221	0.04221	0.04221	0.04221	0.04221	0.03359	0.03196	0.03196	
Eight Flags Purchases-$/KWH			0.07831	0.08979	0.07572	0.07712	0.07956	0.08197	0.08416	0.08273	0.08342	0.08406	0.07830	0.08108	
FPL Base Fuel Costs - $/KWH			0.05423	(0.01491)	0.02711	0.02735	0.03141	0.03474	0.03400	0.03506	0.03542	0.03549	0.03025	0.03967	
FPL Energy Charge - $/KWH			0.00384	0.00076	0.00219	0.00224	0.00195	0.00169	0.00165	0.00169	0.00170	0.00188	0.00206	0.00207	
FPL Demand and Non-Fuel:															
Demand Charge - $/KW			10 68	10.68	10.68	10.68	10.68	10 68	10.68	10.68	10.68	10.68	10.68	10.68	
Transmission Charge $/KW			5.45000	5.45000	5.45000	5.45000	5.45000	5.45000	5.45000	5.45000	5.45000	5.45000	5.45000	5.45000	
Gulf Energy Environmental	Line Loss Fctr.	0.974	0.05561	0.05561	0.05561	0.05561	0.05561	0 05561	0.05561	0.05561	0 05561	0.05561	0.05561	0.05561	
Gulf Fuel Demand and Non-Fuel:															
Capacity Charge-$/KW			12 25000	12.25000	12.25000	12.25000	12.25000	12 25000	12.25000	12 25000	12 25000	12.25000	12.25000	12.25000	
Transmisalon and Interconnection			3 01632	3.01632	3.01632	3.01632	3.01632	3 01632	3 01632	3.01632	3.01632	3.01632	3.01632	3.01632	
Purchased Power Costs:	RockTenn Fuel Costs		46,561	3,423	37,114	11,210	22,279	25,425	23,514	16,728	27,527	16,360	19,357	23,855	273,352
	Rayonier Standby Costs		43,006	48,916	56,817	64,044	62,190	40,101	40,776	46,768	67,920	36,385	13,927	11,072	531,922
	Eight Flags Fuel Costs		1,227,132	1,175,964	1,239,239	1,166,711	1,186,434	1,136,759	1,003,259	1,030,669	1,116,730	1,171,569	1,188,019	1,477,653	14,120,138
	Gulf Base Fuel Costs		1,778,114	1,134,596	1,244,130	1,164,586	1,499,115	1,668,141	1,758,547	1,696,160	1,665,553	841,928	1,171,061	1,308,025	16,929,955
	FPL Base Fuel Costs		1,397,040	(112,220)	198,815	167,818	363,835	691,040	793,160	657,298	731,906	520,737	296,832	400,166	6,106,427
	FPL Fuel Adjustment		98,991	5,738	16,028	13,746	22,591	33,634	38,412	31,619	35,162	27,529	20,243	20,889	364,582
	Subtotal Fuel Costs		4,590,842	2,256,417	2,792,142	2,588,115	3,156,444	3,595,100	3,657,668	3,479,242	3,644,798	2,614,507	2,709,439	3,241,660	38,326,376
Demand and Non-Fuel Costs:	FPL Demand Charge		147,591	149,520	149,520	149,520	149,520	149,520	149,520	149,520	149,520	149,520	149,520	149,520	1,792,311
	FPL Transmission Charge		498,528	60,946	146,281	92,431	158,530	289,629	300,019	339,832	226,262	202,491	147,161	189,813	2,651,923
	FPL Monthly Cust Charge & Net :		166,635	54,513	76,995	56,068	81,889	141,824	129,156	134,822	122,071	122,016	80,096	76,010	1,242,093
	Gulf Capacity Charge		1,114,750	1,114,750	1,114,750	1,114,750	1,114,750	1,114,750	1,114,750	1,114,750	1,114,750	1,114,750	1,114,750	1,114,750	13,377,000
	Southern Transmission/Interc.		163,904	167,482	195,446	170,096	168,445	115,522	165,285	170,714	183,176	170,160	170,872	119,722	1,960,823
	Southern Co Attch K &FERC		2,151	2,632	1,679	1,841	1,724	2,219	2,469	2,603	2,510	2,465	1,277	1,776	25,346
	Souther Co Distr Facility		84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	1,011,034
	Meter Reading and Processing		775	775	775	775	775	775	775	775	775	775	775	775	9,300
Subtotal Demand & Non-Fuel Costs			2,178,587	1,634,871	1,769,699	1,669,733	1,759,886	1,898,492	1,946,226	1,997,269	1,883,316	1,846,430	1,748,704	1,736,619	22,069,831
Total System Purchased Power Costs			6,769,429	3,891,288	4,561,841	4,257,848	4,916,330	5,493,592	5,603,894	5,476,511	5,528,114	4,460,937	4,458,143	4,978,279	60,396,207
Less Direct Billing To GSLD1 Class:		Demand	13,932	4,465	34,314	2,611	3,917	68,011	25,487	15,311	78,246	(29,627)	3,340	47,347	267,355
(these 2 amounts (Demand and comodity) should equal 1		Commodity	60,921	57,130	65,160	42,272	31,609	85,941	49,526	36,796	35,827	46,109	44,878	80,141	636,311
Net Purchased Power Costs			6,694,576	3,829,694	4,462,366	4,212,964	4,880,804	5,339,640	5,528,881	5,424,404	5,414,041	4,444,455	4,409,925	4,850,790	59,492,542
															0
	Special Costs		73,284	44,138	139,450	16,771	55,856	13,357	(524)	16,198	34,017	25,235	(8,217)	64,291	473,855
Total Costs and Charges			6,767,860	3,873,831	4,601,816	4,229,736	4,936,659	5,352,997	5,528,357	5,440,602	5,448,058	4,469,690	4,401,708	4,915,081	59,966,397
Sales Revenues - Fuel Adjustment Revenues:															
RS< 1,000 kwh	0.09313		1,884,620	1,675,526	1,435,111	1,492,599	1,477,837	1,787,458	1,906,245	1,870,799	1,896,183	1,346,336	922,235	3,001,967	20,696,915
RS> 1,000 kwh	0.10562		1,639,187	731,720	258,434	333,449	368,168	945,445	1,295,552	1,157,127	1,275,462	640,426	266,955	1,423,337	10,335,261
GS	0.09384		490,344	408,535	342,864	365,685	376,598	501,898	548,539	530,286	546,312	343,608	209,313	941,899	5,605,882
GSD	0.09023		1,215,788	1,084,570	997,131	1,068,366	1,105,681	1,403,630	1,463,439	1,507,439	1,574,988	928,306	633,563	2,751,704	15,734,606
GSLD	0.08763		554,427	492,006	514,758	554,162	562,936	672,100	709,059	673,758	786,656	353,617	278,450	1,565,704	7,717,633
LS	0.07131		44,031	45,283	45,630	45,393	46,228	45,519	45,766	45,448	45,433	27,499	13,573	124,945	574,746
Unbilled Fuel Revenues			421,846	(739,091)	139,967	(124,925)	280,342	266,305	336,514	(238,721)	(75,421)	(809,821)	186,621	1,777,536	1,421,154
Total Fuel Revenues (Excl. GSLD1)			6,250,242	3,698,549	3,733,895	3,734,729	4,217,790	5,622,355	6,305,114	5,546,136	6,049,613	2,829,972	2,510,709	11,587,092	62,086,197
GSLD1 Fuel Revenues			74,853	61,595	99,475	44,884	35,526	153,952	75,013	52,107	114,073	16,482	48,218	127,488	903,665
Non-Fuel Revenues			2,758,503	2,284,245	1,950,784	2,035,836	1,961,351	2,519,591	2,744,342	2,632,845	2,720,422	1,961,839	1,114,467	2,389,266	27,073,491
Total Sales Revenue			9,083,598	6,044,389	5,784,153	5,815,449	6,214,667	8,295,898	9,124,470	8,231,088	8,884,107	4,808,293	3,673,395	14,103,846	90,063,353
KWH Sales:	RS< 1,000 kwh		20,233,969	17,991,470	15,409,738	16,027,079	15,868,685	19,193,450	20,469,214	20,088,196	20,361,082	18,948,054	9,902,358	30,141,131	224,634,426
	RS> 1,000 kwh		15,518,575	6,927,589	2,446,688	3,156,938	3,485,645	8,951,039	12,265,692	10,955,147	12,075,499	7,501,952	2,527,405	7,025,936	92,838,105
	GS		5,224,765	4,353,415	3,653,612	3,896,794	4,013,083	5,348,305	5,845,312	5,650,817	5,821,587	5,139,366	2,230,468	7,547,664	58,725,188
	GSD		13,476,402	12,034,455	11,061,007	11,855,377	12,268,223	15,571,594	16,233,190	16,732,060	17,476,551	14,863,318	7,022,034	23,194,276	171,788,487
	GSLD		6,327,128	5,614,784	5,874,424	6,324,108	6,424,236	7,670,016	8,091,800	7,688,933	8,977,337	7,890,185	3,177,680	13,103,652	87,164,283
	GSLD1		1,370,000	1,500,000	2,870,000	1,090,000	800,000	2,220,000	1,280,000	950,000	920,000	1,240,000	1,190,000	2,100,000	17,530,000
	LS		625,942	635,119	640,800	636,666	637,402	639,220	641,935	637,442	637,210	632,166	190,319	1,312,361	7,866,582
	Total KWH Sales		62,776,781	49,056,832	41,956,269	42,986,962	43,497,274	59,593,624	64,827,143	62,702,595	66,269,266	56,215,041	26,240,264	84,425,020	660,547,071
True-up Calculation (Excl. GSLD1):															
Fuel Revenues			6,250,242	3,698,549	3,733,895	3,734,729	4,217,790	5,622,355	6,305,114	5,546,136	6,049,613	2,829,972	2,510,709	11,587,092	62,086,197
True-up Provision - collect/(refund)			282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	3,391,416
Gross Receipts Tax Refund															
Fuel Revenue			5,967,624	3,415,931	3,451,277	3,452,111	3,935,172	5,339,737	6,022,496	5,263,518	5,766,995	2,547,354	2,228,091	11,304,474	58,694,781
Net Purchased Power and Other Fuel Costs			6,767,860	3,873,831	4,601,816	4,229,736	4,936,659	5,352,997	5,528,357	5,440,602	5,448,058	4,469,690	4,401,708	4,915,081	59,966,397
True-up Provision for the Period			(800,236)	(457,900)	(1,150,539)	(777,625)	(1,001,487)	(13,260)	494,139	(177,084)	318,936	(1,922,337)	(2,173,617)	6,389,393	(1,271,617)
Interest Provision for the Period			(7,347)	(8,231)	(9,946)	(11,707)	(12,677)	(13,390)	(12,930)	(12,289)	(12,186)	(13,802)	(17,585)	(13,888)	(145,978)
Beginning of Period True-up and Interest Provision			(5,637,395)	(6,162,360)	(6,345,873)	(7,223,741)	(7,730,455)	(8,462,001)	(8,206,033)	(7,442,206)	(7,348,960)	(6,759,592)	(8,413,113)	(10,321,697)	(5,637,395)
True-up Collected or (Refunded)			282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	282,618	3,391,416
Federal Tax Savings														2,181,243	2,181,243
End of Period, Net True-up and Int. Prov.			(6,162,360)	(6,345,873)	(7,223,741)	(7,730,455)	(8,462,001)	(8,206,033)	(7,442,206)	(7,348,960)	(6,759,592)	(8,413,113)	(10,321,697)	(1,482,331)	(1,482,331)
Beginning True-up Amount			(5,637,395)	(6,162,360)	(6,345,873)	(7,223,741)	(7,730,455)	(8,462,001)	(8,206,033)	(7,442,206)	(7,348,960)	(6,759,592)	(8,413,113)	(10,321,697)	
Ending True-up Amount Before Interest			(6,155,013)	(6,337,642)	(7,213,795)	(7,718,748)	(8,449,324)	(8,192,643)	(7,429,275)	(7,336,671)	(6,747,406)	(8,399,311)	(10,304,112)	(3,649,686)	10% Rule Interest Provision:
Total Beginning and Ending True-up			(11,792,409)	(12,500,003)	(13,559,668)	(14,942,488)	(16,179,778)	(16,654,644)	(15,635,308)	(14,778,877)	(14,096,367)	(15,158,905)	(18,717,225)	(13,971,383)	-2.45%
Average True-up Amount			(5,896,204)	(6,250,001)	(6,779,834)	(7,471,244)	(8,089,889)	(8,327,322)	(7,817,654)	(7,389,439)	(7,048,183)	(7,579,452)	(9,358,613)	(6,985,692)	
Average Annual Interest Rate			1.4950%	1.5800%	1.7600%	1.8800%	1.8800%	1.9300%	1.9850%	1.9950%	2.0750%	2.1850%	2.2550%	2.3850%	
Interest Provision			(7,347)	(8,231)	(9,946)	(11,707)	(12,677)	(13,390)	(12,930)	(12,289)	(12,186)	(13,802)	(17,585)	(13,888)	

Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2019 - DECEMBER 2019
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Florida Division -CONSOLIDATED

Under-recovery of purchased power costs for the period January 2019 - December 2019. (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 2019.)(Estimated)	$	1,934,452

Exhibit No._____
DOCKET NO. 20190001-EI
Florida Public Utilities Company
(CDY-2)
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 50
PARTY: FLORIDA PUBLIC UTILITIES COMPANY – (DIRECT)
DESCRIPTION: Curtis D. Young CDY-2

FLORIDA PUBLIC UTILITIES COMPANY

Schedule E-1b

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

CONSOLIDATED

	ACTUAL Jan 2019	ACTUAL Feb 2019	ACTUAL Mar 2019	ACTUAL Apr 2019	ACTUAL May 2019	ACTUAL Jun 2019	Estimated Jul 2019	Estimated Aug 2019	Estimated Sep 2019	Estimated Oct 2019	Estimated Nov 2019	Estimated Dec 2019	Total
Total System Sales - KWH	49,458,300	50,689,267	36,576,538	43,490,580	49,217,862	63,808,711	63,677,740	63,802,881	63,357,176	51,437,255	46,883,116	50,997,866	633,397,292
West-Rock Purchases - KWH	1,100,000	1,660,000	700,000	1,180,000	910,000	590,000	700,000	400,000	700,000	900,000	500,000	700,000	10,040,000
Rayonier Purchases - KWH - On Peak	257,138	17,375	405,716	503,036	325,908	140,022	310,500	310,500	310,500	310,500	310,500	310,500	3,512,195
Rayonier Purchases - KWH - Off Peak	314,524	46,414	738,955	1,096,759	781,238	259,760	589,500	589,500	589,500	589,500	589,500	589,500	6,774,650
Eight Flags Purchases - KWH - KWH	13,766,429	9,583,689	17,099,478	16,306,914	16,338,420	15,285,031	12,500,000	12,800,000	12,400,000	15,500,000	15,200,000	15,800,000	172,579,961
FPL Purchases - KWH	15,952,593	12,110,849	6,435,820	6,170,899	15,062,347	20,482,838	26,467,386	26,219,853	25,566,924	16,965,475	12,211,924	10,368,183	194,015,090
Gulf Purchases - KWH	24,797,417	18,315,462	20,326,293	19,981,205	27,436,089	29,167,339	31,306,575	31,361,913	31,523,953	27,134,816	23,151,348	23,385,966	307,888,377
Generation Demand - KW - FPL	53,591	47,104	38,957	35,824	51,457	74,600	65,500	68,900	56,400	49,500	47,300	46,700	635,833
Generation Demand - KW - Gulf	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	1,092,000
Transmission Demand - KW - FPL	0	33,272	39,339	53,184	60,712	81,794	69,000	72,400	59,900	53,000	50,800	50,200	623,601
Transmission Demand - KW - Southern	57,049	55,832	54,695	54,739	54,857	55,436	55,500	55,500	55,500	55,500	55,500	55,500	665,608
Purchased Power Rates:													
West Rock Fuel Costs - $/KWH	0.03612	0.03476	0.03189	0.03189	0.03259	0.03758	0.04221	0.04221	0.04221	0.04221	0.04221	0.04221	
Rayonier Energy Charge - On Peak - $/KWH	0.02914	0.02914	0.02914	0.05842	0.06717	0.03090	0.04964	0.04964	0.04964	0.04964	0.04964	0.04964	
Rayonier Energy Charge - Off Peak - $/KWH	0.02715	0.02715	0.02715	0.02550	0.02866	0.02866	0.04964	0.04964	0.04964	0.04964	0.04964	0.04964	
Eight Flags Charge - $/KWH	0.09196	0.08392	0.06745	0.07641	0.07494	0.07655	0.08382	0.08382	0.08382	0.08382	0.08382	0.08382	
Base Fuel Costs - $/KWH - FPL	0.03446	0.03057	0.02961	0.02674	0.03021	0.02936	0.03573	0.03569	0.03588	0.03554	0.03459	0.03006	
Base Fuel Costs - $/KWH GULF 0.974	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	
Energy Charge - $/KWH - FPL	0.00182	0.00186	0.00217	0.00222	0.00189	0.00173	0.00161	0.00161	0.00159	0.00163	0.00172	0.00215	
Demand and Non-Fuel:													
Demand Charge - $/KW - FPL	6.85	7.04	7.37	7.54	6.90	6.37	6.59	6.54	6.78	6.96	7.03	7.05	
Demand Charge - $/KW - Gulf	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	
Distribution Facility Charge	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	
Transmission Charge $/KW - FPL	1.85	1.85	1.72	1.68	1.85	1.94	1.85	1.85	1.85	1.85	1.85	1.85	
Transmission Charge $/KW - Southern	3.01633	2.98080	3.03851	3.01615	2.41913	3.01633	3.01632	3.01632	3.01632	3.01632	3.01632	3.01632	
Purchased Power Costs:													
RockTenn Fuel Costs	39,736	57,706	22,322	37,628	29,655	22,175	29,549	16,885	29,549	37,991	21,106	29,549	373,851
Rayonier Standby Costs	16,032	1,766	31,885	57,355	44,282	11,772	44,676	44,676	44,676	44,676	44,676	44,676	431,148
Eight Flags	1,265,905	804,229	1,153,311	1,246,011	1,224,348	1,170,121	1,047,750	1,072,896	1,039,368	1,299,210	1,274,064	1,324,356	13,921,569
Gulf Base Fuel Costs	1,231,215	909,380	1,009,219	992,085	1,362,227	1,448,185	1,554,400	1,557,148	1,565,193	1,347,269	1,149,486	1,161,135	15,286,942
FPL Base Fuel Costs	549,787	370,283	190,554	164,999	455,064	601,329	945,744	935,724	917,269	602,992	422,426	311,625	6,467,796
FPL Fuel Adjustment	29,067	22,544	13,941	13,675	28,421	35,471	42,547	42,262	40,742	27,583	20,974	22,340	339,567
Subtotal Fuel Costs	3,131,742	2,165,908	2,421,232	2,511,753	3,143,997	3,289,053	3,684,666	3,669,591	3,636,797	3,359,721	2,932,732	2,893,681	36,820,872
Demand and Non-Fuel Costs: Demand Capacity Charge	1,531,632	1,496,279	1,451,876	1,434,801	1,520,001	1,639,912	1,596,535	1,615,065	1,546,940	1,509,335	1,497,345	1,494,075	18,333,796
Distr. Fac. Charge	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	1,011,034
FERC & Meter Reading	4,759	4,922	4,361	4,535	4,505	5,151	5,301	5,486	5,491	5,505	5,125	4,780	59,921
Transmission Charge	172,079	228,113	233,918	254,463	244,856	326,077	295,338	301,642	278,466	265,672	261,593	260,481	3,122,698
Subtotal Demand & Non-Fuel Costs	1,792,723	1,813,567	1,774,408	1,778,052	1,853,615	2,055,393	1,981,427	2,006,446	1,915,150	1,864,765	1,848,316	1,843,589	22,527,449
Total System Purchased Power Costs	4,924,465	3,979,475	4,195,640	4,289,805	4,997,611	5,344,446	5,666,093	5,676,037	5,551,947	5,224,486	4,781,048	4,737,270	59,348,321
Less Direct Billing To GSLD1 Class: Demand	52,290	50,467	30,568	43,957	43,015	43,310	29,138	29,138	29,138	29,138	29,138	29,138	438,435
Commodity	144,384	71,673	46,116	18,783	38,412	72,334	37,760	109,747	105,508	146,031	184,460	136,273	1,111,482
Net Purchased Power Costs	4,727,791	3,857,335	4,118,955	4,227,065	4,916,185	5,228,802	5,579,195	5,537,152	5,417,300	5,049,317	4,567,450	4,571,859	57,798,404
	0	0	0	0	0	0	0	0	0	0	0	0	0
Special Costs*	64,554	6,129	41,721	42,872	(21,458)	26,992	17,850	17,850	18,300	17,850	17,850	20,300	271,810
Total Costs and Charges	4,792,344	3,863,464	4,160,676	4,269,936	4,894,727	5,255,794	5,597,045	5,555,002	5,436,600	5,067,167	4,585,300	4,592,159	58,070,214
Sales Revenues - Fuel Adjustment Revenues:													
RS< 0.09519	1,721,442	1,816,047	1,448,522	1,473,399	1,634,898	1,911,278	1,894,713	1,902,854	1,883,244	1,682,192	1,532,262	1,637,722	20,538,571
RS> 0.10768	690,876	519,744	272,802	283,241	584,259	1,250,725	1,372,118	1,275,915	1,212,310	719,689	381,418	558,229	9,121,326
GS 0.09557	369,597	375,162	324,303	350,150	418,030	546,639	538,885	561,497	547,987	439,185	416,165	456,730	5,344,330
GSD 0.09134	1,101,938	1,058,108	940,923	1,081,551	1,243,896	1,492,030	1,481,341	1,527,685	1,540,933	1,324,892	1,283,035	1,366,724	15,443,156
GSLD 0.08836	592,770	543,460	291,781	744,502	615,851	668,297	671,180	643,917	682,334	577,219	556,411	551,994	7,139,716
LS 0.06947	42,490	43,467	42,483	44,681	44,245	44,483	43,715	43,550	43,723	43,387	43,204	43,117	522,545
Unbilled Fuel Revenues	(2,250,523)	1,183,425	(1,189,949)	1,195,138	(600,560)	861,574	62,500	62,500	62,500	62,500	62,500	62,500	(425,895)
Total Fuel Revenues (Excl. GSLD1)	2,268,590	5,539,413	2,130,865	5,172,662	3,940,717	6,775,026	6,064,452	6,017,918	5,973,031	4,849,064	4,274,995	4,677,016	57,683,749
GSLD1 Fuel Revenues .17197	196,674	122,140	76,684	62,740	81,427	115,644	66,898	138,885	134,646	175,169	213,598	165,411	1,549,917
Non-Fuel Revenues	6,618,334	2,155,388	1,718,849	1,946,086	1,605,871	2,807,026	3,167,224	2,975,578	2,546,304	1,941,858	2,369,448	2,711,799	32,563,765
Total Sales Revenue	9,083,598	7,816,942	3,926,398	7,181,488	5,628,015	9,697,695	9,298,575	9,132,381	8,653,981	6,966,091	6,858,040	7,554,226	91,797,431
KWH Sales: RS<	17,664,507	17,628,817	15,210,704	15,450,076	17,143,105	20,078,126	19,904,234	19,989,756	19,783,747	17,671,667	16,096,633	17,204,508	213,825,879
RS>	6,414,274	6,059,209	2,533,093	2,630,335	5,441,828	11,614,936	12,742,260	11,848,861	11,258,197	6,683,439	3,542,065	5,184,033	85,952,530
GS	3,865,037	3,924,910	3,389,224	3,660,161	4,370,380	5,722,667	5,638,572	5,875,171	5,733,805	4,595,374	4,354,505	4,778,952	55,908,758
GSD	12,075,157	11,550,441	10,309,238	11,796,013	13,626,164	16,346,585	16,217,127	16,724,484	16,869,517	14,504,381	14,046,153	14,962,351	169,027,611
GSLD	6,708,857	7,150,768	3,302,316	8,107,502	6,970,084	7,563,654	7,596,285	7,287,725	7,722,525	6,532,847	6,297,347	6,247,361	81,487,271
GSLD1	2,100,000	3,750,000	1,210,000	1,210,000	1,030,000	1,840,000	950,000	1,450,000	1,360,000	825,000	1,924,500	2,000,000	19,649,500
LS	630,468	625,122	621,963	636,493	636,300	642,743	629,262	626,884	629,385	624,546	621,914	620,663	7,545,744
Total KWH Sales	49,458,300	50,689,267	36,576,538	43,490,580	49,217,862	63,808,711	63,677,740	63,802,881	63,357,176	51,437,255	46,883,116	50,997,866	633,397,292
True-up Calculation (Excl. GSLD1):													
Fuel Revenues	2,268,590	5,539,413	2,130,865	5,172,662	3,940,717	6,775,026	6,064,452	6,017,918	5,973,031	4,849,064	4,274,995	4,677,016	57,683,749
True-up Provision - collect/(refund)	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,818	3,957,772
Gross Receipts Tax Refund													0
Fuel Revenue	1,938,776	5,209,599	1,801,051	4,842,848	3,610,903	6,445,212	5,734,638	5,688,104	5,643,217	4,519,250	3,945,181	4,347,198	53,725,977
Net Purchased Power and Other Fuel Costs	4,792,344	3,863,464	4,160,676	4,269,936	4,894,727	5,255,794	5,597,045	5,555,002	5,436,600	5,067,167	4,585,300	4,592,159	58,070,214
True-up Provision for the Period	(2,853,569)	1,346,135	(2,359,625)	572,912	(1,283,824)	1,189,418	137,593	133,102	206,617	(547,917)	(640,119)	(244,961)	(4,344,236)
Interest Provision for the Period	(5,626)	(6,401)	(6,785)	(7,937)	(7,989)	(7,218)	(5,287)	(4,387)	(3,417)	(3,112)	(3,635)	(3,863)	(65,657)
Beginning of Period True-up and Interest Provision	(1,482,331)	(4,011,712)	(2,342,163)	(4,378,759)	(3,483,971)	(4,445,969)	(2,933,955)	(2,471,835)	(2,013,305)	(1,480,292)	(1,701,507)	(2,015,447)	(1,482,331)
True-up Collected or (Refunded)	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,818	3,957,772
Adjustment for Tax Settlement													0
End of Period, Net True-up and Int. Prov.	(4,011,712)	(2,342,163)	(4,378,759)	(3,483,971)	(4,445,969)	(2,933,955)	(2,471,835)	(2,013,305)	(1,480,292)	(1,701,507)	(2,015,447)	(1,934,452)	(1,934,452)
Beginning True-up Amount	(1,482,331)	(4,011,712)	(2,342,163)	(4,378,759)	(3,483,971)	(4,445,969)	(2,933,955)	(2,471,835)	(2,013,305)	(1,480,292)	(1,701,507)	(2,015,447)	
Ending True-up Amount Before Interest	(4,006,086)	(2,335,762)	(4,371,974)	(3,476,034)	(4,437,980)	(2,926,737)	(2,466,548)	(2,008,918)	(1,476,875)	(1,698,395)	(2,011,812)	(1,930,589)	
Total Beginning and Ending True-up	(5,488,417)	(6,347,474)	(6,714,138)	(7,854,793)	(7,921,951)	(7,372,707)	(5,400,503)	(4,480,753)	(3,490,180)	(3,178,686)	(3,713,318)	(3,946,036)	
Average True-up Amount	(2,744,208)	(3,173,737)	(3,357,069)	(3,927,397)	(3,960,975)	(3,686,353)	(2,700,252)	(2,240,377)	(1,745,090)	(1,589,343)	(1,856,659)	(1,973,018)	
Average Annual Interest Rate	2.4600%	2.4200%	2.4250%	2.4250%	2.4200%	2.3500%	2.3500%	2.3500%	2.3500%	2.3500%	2.3500%	2.3500%	
Interest Provision	(5,626)	(6,401)	(6,785)	(7,937)	(7,989)	(7,218)	(5,287)	(4,387)	(3,417)	(3,112)	(3,635)	(3,863)	

10% Rule Interest Provision: -3.26%

* Includes: Consulting fees, Legal fees and Taxes on Company Use.

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Florida Public Utilities Company
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FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED FLORIDA DIVISIONS
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2019 - DECEMBER 2019

	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)	22,094,305	22,731,550	(637,246)	-2.8%	501,903	512,450	(10,547)	-2.1%	4.40211	4.43586	(0.03375)	-0.8%
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)	22,527,449	23,266,824	(739,375)	-3.2%	501,903	512,450	(10,547)	-2.1%	4.48841	4.54031	(0.05190)	-1.1%
11 Energy Payments to Qualifying Facilities (A8a)	14,726,568	14,943,319	(216,751)	-1.5%	192,907	193,850	(943)	-0.5%	7.63402	7.70870	(0.07468)	-1.0%
12 TOTAL COST OF PURCHASED POWER	59,348,321	60,941,693	(1,593,372)	-2.6%	694,810	706,300	(11,490)	-1.6%	8.54166	8.62830	(0.08664)	-1.0%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					694,810	706,300	(11,490)	-1.6%				
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)	271,810	221,000	50,810	23.0%								
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	271,810	221,000	50,810	23.0%	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)	59,620,131	61,162,693	(1,542,562)	-2.5%	694,810	706,300	(11,490)	-1.6%	8.58078	8.65959	(0.07881)	-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)	49,511 *	57,500 *	(7,989)	-13.9%	577	664	(87)	-13.1%	0.00782	0.00839	(0.00057)	-6.8%
23 T & D Losses (A4)	5,220,203 *	1,723,951 *	3,496,252	202.8%	60,836	19,908	40,928	205.6%	0.82416	0.25140	0.57276	227.8%
24 SYSTEM KWH SALES	59,620,131	61,162,693	(1,542,562)	-2.5%	633,397	685,728	(52,331)	-7.6%	9.41276	8.91938	0.49338	5.5%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	59,620,131	61,162,693	(1,542,562)	-2.5%	633,397	685,728	(52,331)	-7.6%	9.41276	8.91938	0.49338	5.5%
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	59,620,131	61,162,693	(1,542,562)	-2.5%	633,397	685,728	(52,331)	-7.6%	9.41276	8.91938	0.49338	5.5%
28 GPIF**												
29 TRUE-UP**	3,957,772	3,957,772	0	0.0%	633,397	685,728	(52,331)	-7.6%	0.62485	0.57716	0.04769	8.3%
30 TOTAL JURISDICTIONAL FUEL COST	63,577,903	65,120,465	(1,542,562)	-2.4%	633,397	685,728	(52,331)	-7.6%	10.03761	9.49654	0.54107	5.7%
31 Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									10.04484	9.50338	0.54146	5.7%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									10.045	9.503	0.542	5.7%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 51
PARTY: FLORIDA PUBLIC UTILITIES COMPANY – (DIRECT)
DESCRIPTION: Michelle Napier MDN-1

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

	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)	12,007,308		429,024	2.79875
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)	15,241,005		429,024	3.55248
10a	Demand Costs of Purchased Power	14,065,448	*		
10b	Non-fuel Energy & Customer Costs of Purchased Power	1,175,558	*		
11	Energy Payments to Qualifying Facilities (E8a)	15,601,107		193,850	8.04803
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	42,849,420		622,874	6.87931
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	42,849,420		622,874	6.87931
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)	42,849,420		622,874	6.87931
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	45,679	*	664	0.00763
23	T & D Losses	1,615,524	*	23,484	0.26983
24	SYSTEM MWH SALES	42,849,420		598,726	7.15676
25	Wholesale MWH Sales				
26	Jurisdictional MWH Sales	42,849,420		598,726	7.15676
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	42,849,420		598,726	7.15677
27a	GSLD1 MWH Sales			14,860	
27b	Other Classes MWH Sales			583,866	
27c	GSLD1 CP KW			90,000	*
28	Projected Unbilled Revenues	0		583,866	0.00000
29	GPIF **				
30	TRUE-UP (OVER) UNDER RECOVERY **	1,934,452		583,866	0.33132
31	TOTAL JURISDICTIONAL FUEL COST	44,783,872		583,866	7.67023
31a	Demand Purchased Power Costs (Line 10a)	14,065,448	*		
31b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	28,783,973	*		
31c	True up Over/Under Recovery (Line 29)	1,934,452	*		
31d	Unbilled Revenues	0			

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

REVISED

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FLORIDA PUBLIC UTILITIES COMPANY
(MDN-1)
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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

	FLORIDA DIVISION-CONSOLIDATED	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 31a)	14,065,448		
32	GSLD1 Portion of Demand Costs (Line 31a) Including Line Losses(Line 27c x $5.85)	364,884	370,900 (KW)	$0.98 /KW
33	Balance to Other Classes	13,700,564	583,866	2.34652
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 31b)	28,783,973		
35	Total KWH Purchased (Line 12)		622,874 KWH	
36	Average Cost per KWH Purchased			4.62115
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			4.75978
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	910,941	14,860	6.13015
39	Balance to Other Classes	27,873,032	583,866	4.77387
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	364,884	370,900 (KW)	$0.98 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$0.98 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	910,941	14,860	6.13015
40e	Total Non-demand Costs Including True-up	910,941	14,860	6.13015
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			6.13456
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	41,573,596	583,866	7.12040
41b	Less: Total Demand Cost Recovery	13,700,564 ***		
41c	Total Other Costs to be Recovered	27,873,032	583,866	4.77387
41d	Unbilled Revenue	0	583,866	0.00000
41e	Other Classes' Portion of True-up (Line 30c)	1,934,452	583,866	0.33132
41f	Total Demand & Non-demand Costs Including True-up	29,807,484	583,866	5.10519
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	29,828,945		5.109

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

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	274,540,960	57.542%	54,464.7	1.089	1.030	59,312.1	282,777,189	53.71%	47.03%
45	GS	53,476,045	63.463%	9,619.1	1.089	1.030	10,475.2	55,080,326	9.49%	9.16%
46	GSD	164,607,934	73.488%	25,569.9	1.089	1.030	27,845.6	169,546,172	25.21%	28.19%
47	GSLD	83,743,267	82.761%	11,551.1	1.089	1.030	12,579.1	86,255,565	11.39%	14.34%
48	LS	7,497,990	416.653%	205.4	1.089	1.030	223.7	7,722,930	0.20%	1.28%
49		0	416.653%	0.0	1.089	1.030	0.0	0	0.00%	0.00%
	TOTAL	583,866,196		101,410.2			110,435.7	601,382,182	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (9)	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
50	RS	49.59%	3.62%	53.21%	$7,290,070	0.02655	0.02657	0.05109	$ 0.07766
51	GS	8.76%	0.70%	9.46%	1,296,073	0.02424	0.02426	0.05109	$ 0.07535
52	GSD	23.27%	2.17%	25.44%	3,485,423	0.02117	0.02119	0.05109	$ 0.07228
53	GSLD	10.51%	1.10%	11.61%	1,590,635	0.01899	0.01900	0.05109	$ 0.07009
54	LS	0.18%	0.10%	0.28%	38,362	0.00512	0.00512	0.05109	$ 0.05621
	TOTAL	92.31%	7.69%	100.00%	$13,700,564				

Step Rate Allocation for Residential Customers

		(18)		(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation		Annual kWh	Levelized Adj.	Revenues
56	RS	Sales		274,540,960	$0.07766	$21,320,851
57	RS	<= 1,000kWh/mo.		207,213,211	$0.07459	$15,456,972
58	RS	> 1,000 kWh/mo.		67,327,749	$0.08709	$5,863,879
59	RS	Total Sales		274,540,960		$21,320,851

(2) From Gulf Power 2015 Load Research results.

TOU Rates

		(22) On Peak Rate Differential	(23) Off Peak Rate Differential	(24) Levelized Adj. On Peak	(25) Levelized Adj. Off Peak
	Rate Schedule				
60	RS	0.0840	(0.0390)	$0.15859	$0.03559
61	GS	0.0400	(0.0500)	$0.11535	$0.02535
62	GSD	0.0400	(0.0325)	$0.11228	$0.03978
63	GSLD	0.0600	(0.0300)	$0.13009	$0.04009
64	Interruptible	(0.0150)	-	$0.05509	$0.07009

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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2019 - DECEMBER 2019
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

FLORIDA DIVISION-CONSOLIDATED

Under-recovery of purchased power costs for the period January 2019 - December 2019. (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 2019.)(Estimated)	$	1,934,452
Portion of 2019 Under-recovery to be collected for the period January 2020 - December 2020	$	1,934,452
Estimated kilowatt hour sales for the months of January 2020 - December 2020 as per estimate filed with the Commission. (Excludes GSLD1 customers)		583,866,196
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2020- December 2020		0.33132

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Florida Public Utilities Company
(MDN-1)

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) ESTIMATED JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
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		678,819	855,163	748,610	850,467	865,282	1,245,385	1,261,864	1,246,956	1,267,035	1,225,982	983,474	778,272	12,007,308	3
3a	DEMAND & NON FUEL COST OF PUR POWER		1,485,147	1,138,209	1,098,553	953,772	1,160,739	1,399,731	1,433,295	1,453,992	1,327,704	1,232,886	1,121,001	1,214,977	15,020,005	3a
3b	QUALIFYING FACILITIES		1,392,584	1,263,018	1,422,181	1,315,033	1,440,951	1,263,018	1,122,625	1,137,100	1,114,152	1,384,111	1,344,100	1,402,234	15,601,107	3b
4	OTHER FUEL RELATED COSTS		17,850	17,850	19,300	17,850	17,850	19,300	17,850	17,850	19,300	17,850	17,850	20,300	221,000	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		3,574,400	3,274,239	3,288,644	3,137,123	3,484,821	3,927,434	3,835,634	3,855,898	3,728,191	3,860,829	3,466,424	3,415,784	42,849,420	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,382,940	1,041,376	1,005,781	860,312	1,054,380	1,273,636	1,303,282	1,324,484	1,200,878	1,121,736	1,023,045	1,108,713	13,700,564	5a
5b	TOTAL OTHER COST TO BE RECOVERED		2,191,460	2,232,863	2,282,863	2,276,810	2,430,441	2,653,798	2,532,351	2,531,414	2,527,313	2,739,092	2,443,380	2,307,070	29,148,857	5b
6	APPORTIONMENT TO GSLD1 CLASS		121,924	125,385	143,590	101,701	83,750	153,991	98,607	81,593	81,383	85,508	90,943	107,450	1,275,825	6
6a	BALANCE TO OTHER CLASSES		2,069,535	2,107,478	2,139,274	2,175,110	2,346,691	2,499,807	2,433,744	2,449,821	2,445,930	2,653,584	2,352,437	2,199,621	27,873,032	6a
6b	SYSTEM KWH SOLD (MWH)		43,220	44,027	42,893	43,751	48,090	57,445	57,013	56,620	56,396	55,663	47,634	45,974	598,726	6b
7	GSLD1 MWH SOLD		1,370	1,500	1,650	1,090	800	2,220	1,280	950	950	920	940	1,190	14,860	7
7a	BALANCE MWH SOLD OTHER CLASSES		41,850	42,527	41,243	42,661	47,290	55,225	55,733	55,670	55,446	54,743	46,694	44,784	583,866	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		4.94518	4.95566	5.18698	5.09864	4.96239	4.52655	4.36679	4.40058	4.41134	4.84733	5.03801	4.91158	4.77387	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)		4.94518	4.95566	5.18698	5.09864	4.96239	4.52655	4.36679	4.40058	4.41134	4.84733	5.03801	4.91158	4.77387	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)	1,934,452	0.33132	0.33132	0.33132	0.33132	0.33132	0.33132	0.33132	0.33132	0.33132	0.33132	0.33132	0.33132	0.33132	12
13	TOTAL		5.27650	5.28698	5.51830	5.42996	5.29371	4.85787	4.69811	4.73190	4.74266	5.17865	5.36933	5.24290	5.10519	13
14	REVENUE TAX FACTOR	0.00072	0.00380	0.00381	0.00397	0.00391	0.00381	0.00350	0.00338	0.00341	0.00341	0.00373	0.00387	0.00377	0.00368	14
15	RECOVERY FACTOR ADJUSTED FOR TAXES		5.28030	5.29079	5.52227	5.43387	5.29752	4.86137	4.70149	4.73531	4.74607	5.18238	5.37320	5.24667	5.10887	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		5.28	5.291	5.522	5.434	5.298	4.861	4.701	4.735	4.746	5.182	5.373	5.247	5.109	16

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FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(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 (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2020	FPL / GULF POWER	MS	27,980,520			27,980,520	2.426042	7.733829	678,819
FEBRUARY 2020	FPL / GULF POWER	MS	30,527,976			30,527,976	2.801242	6.529654	855,163
MARCH 2020	FPL / GULF POWER	MS	27,487,800			27,487,800	2.723427	6.719938	748,610
APRIL 2020	FPL / GULF POWER	MS	29,738,072			29,738,072	2.859860	6.067104	850,467
MAY 2020	FPL / GULF POWER	MS	32,694,024			32,694,024	2.646605	6.196914	865,282
JUNE 2020	FPL / GULF POWER	MS	44,617,739			44,617,739	2.791234	5.928396	1,245,385
JULY 2020	FPL / GULF POWER	MS	45,763,680			45,763,680	2.757348	5.889296	1,261,864
AUGUST 2020	FPL / GULF POWER	MS	45,351,500			45,351,500	2.749535	5.955587	1,246,956
SEPTEMBER 2020	FPL / GULF POWER	MS	39,427,982			39,427,982	3.213542	6.580958	1,267,035
OCTOBER 2020	FPL / GULF POWER	MS	41,146,357			41,146,357	2.979564	5.975907	1,225,982
NOVEMBER 2020	FPL / GULF POWER	MS	33,415,419			33,415,419	2.943173	6.297914	983,474
DECEMBER 2020	FPL / GULF POWER	MS	30,873,118			30,873,118	2.520873	6.456263	778,272
TOTAL			429,024,186	0	0	429,024,186	2.798749	6.299718	12,007,308

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SCHEDULE E8

FLORIDA PUBLIC UTILITIES COMPANY

FLORIDA DIVISION-CONSOLIDATED

PURCHASED POWER

ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(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 (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		17,400,000			17,400,000	8.003356	8.003356	1,392,584
FEBRUARY 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,700,000			15,700,000	8.044701	8.044701	1,263,018
MARCH 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		17,550,000			17,550,000	8.103595	8.103595	1,422,181
APRIL 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		16,200,000			16,200,000	8.117488	8.117488	1,315,033
MAY 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		17,800,000			17,800,000	8.095230	8.095230	1,440,951
JUNE 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		15,700,000			15,700,000	8.044701	8.044701	1,263,018
JULY 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		14,100,000			14,100,000	7.961879	7.961879	1,122,625
AUGUST 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		14,100,000			14,100,000	8.064539	8.064539	1,137,100
SEPTEMBER 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		14,000,000			14,000,000	7.958229	7.958229	1,114,152
OCTOBER 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		17,300,000			17,300,000	8.000642	8.000642	1,384,111
NOVEMBER 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		16,600,000			16,600,000	8.096988	8.096988	1,344,100
DECEMBER 2020	WEST-ROCK / RAYONIER / EIGHT FLAGS		17,400,000			17,400,000	8.058816	8.058816	1,402,234
TOTAL			193,850,000	0	0	193,850,000	8.048030	8.048030	15,601,107

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SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

	JANUARY 2020	FEBRUARY 2020	MARCH 2020	APRIL 2020	MAY 2020	JUNE 2020	JULY 2020
BASE RATE REVENUES ** $	37.77	37.77	37.77	37.77	37.77	37.77	37.77
FUEL RECOVERY FACTOR CENTS/KWH	7.46	7.46	7.46	7.46	7.46	7.46	7.46
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	74.59	74.59	74.59	74.59	74.59	74.59	74.59
GROSS RECEIPTS TAX	2.88	2.88	2.88	2.88	2.88	2.88	2.88
TOTAL REVENUES *** $	115.24	115.24	115.24	115.24	115.24	115.24	115.24

	AUGUST 2020	SEPTEMBER 2020	OCTOBER 2020	NOVEMBER 2020	DECEMBER 2020	PERIOD TOTAL
BASE RATE REVENUES ** $	37.77	37.77	37.77	37.77	37.77	453.24
FUEL RECOVERY FACTOR CENTS/KWH	7.46	7.46	7.46	7.46	7.46	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	74.59	74.59	74.59	74.59	74.59	895.08
GROSS RECEIPTS TAX	2.88	2.88	2.88	2.88	2.88	34.56
TOTAL REVENUES *** $	115.24	115.24	115.24	115.24	115.24	1,382.88

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA
** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.69
CENTS/KWH	20.57
CONSERVATION FACTOR	0.97
STORM SURCHARGE	1.54
	37.77

*** EXCLUDES FRANCHISE TAXES

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Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2018 - DECEMBER 2018

1. Estimated over/(under)-recovery for the period January 2018 - December 2018 (Schedule E-1B, Line 9, filed August 24, 2018) approved in FPSC Order No. PSC-2018-0610-FOF-EI issued on December 26, 2018)	$ 13,195,558
2. Actual over/(under)-recovery for the period January 2018 - December 2018 (December 2018 Schedule A-2, page 2 of 3, "Period-to-Date", Lines 7 + 8 + 12, included in Exhibit CSB-2)	17,707,628
3. Amount to be refunded/(recovered) in the January 2020 - December 2020 projection period (Line 2 - Line 1)	$ 4,512,071

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 52
PARTY: GULF POWER – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-1

Schedule 2

GULF POWER COMPANY
FUEL VARIANCES SUMMARY
ACTUAL vs. ESTIMATED
FOR THE PERIOD
JANUARY 2018 THROUGH DECEMBER 2018

	2018 Final True-Up	2018 Actual/ Estimated[1]	Difference	Percent Variance
Fuel Cost of System Generation (incl. adj.)	291,564,766	272,054,316	19,510,450	7.17%
Fuel Cost of Hedging Settlement	11,832,300	15,213,980	(3,381,680)	-22.23%
Flint Credit	(7,434,492)	(7,033,588)	(400,904)	5.70%
Total Fuel Cost & Gains on Power Sales	(123,204,069)	(103,604,582)	(19,599,487)	18.92%
Total Cost of Purchased Power	211,899,427	204,517,999	7,381,428	3.61%
TOTAL FUEL & NET POWER TRANSACTIONS	384,657,932	381,148,125	3,509,807	0.92%
Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	350,111,657	341,711,388	8,400,269	2.46%
True-Up Provision	(32,650,765)	(32,650,765)	0	0.00%
Incentive Provision	2,041,755	2,041,755	0	0.00%
Tax Savings Credit	73,198,667	73,198,667	0	0.00%
FUEL REVENUE APPLICABLE TO PERIOD	392,701,314	384,301,045	8,400,269	2.19%
Fuel Cost of System Generation (MWH)	9,320,038	9,348,372	(28,334)	-0.30%
Flint Credit (MWH)	(267,883)	(258,152)	(9,731)	3.77%
Total Fuel Cost & Gains on Power Sales (MWH)	(3,701,704)	(3,668,716)	(32,988)	0.90%
Total Cost of Purchased Power (MWH)	6,432,547	6,464,902	(32,355)	-0.50%
TOTAL FUEL & NET POWER TRANSACTIONS (MWH)	11,782,999	11,886,406	(103,408)	-0.87%
Fuel Cost of System Generation (¢/kWh)	3.128	2.910	0.218	7.50%
Total Fuel Cost & Gains on Power Sales (¢/kWh)	3.328	2.824	0.504	17.86%
Total Cost of Purchased Power (¢/kWh)	3.294	3.164	0.131	4.13%
TOTAL FUEL & NET POWER TRANSACTIONS (¢/kWh)	3.265	3.207	0.853	26.61%
COMPARATIVE DATA BY MAJOR FUEL TYPE				
COAL + GAS B.L. + OIL B.L.				
Total Dollar	165,248,026	151,412,247	13,835,779	9.14%
BTUs Burned	56,967,319	53,682,920	3,284,399	6.12%
$/mmBtu	2.90	2.82	0.08	2.85%
Generation (MWh)	5,258,482	4,885,697	372,785	7.63%
Fuel Costs (¢ / kWh)	3.14	3.10	0.04	1.29%
GAS - Generation				
Total Dollar	117,849,813	110,130,107	7,719,706	7.01%
BTUs Burned	28,974,096	29,046,000	(71,904)	-0.25%
$/mmBtu	4.07	3.79	0.28	7.28%
Generation (MWh)	4,037,196	4,099,946	(62,750)	-1.53%
Fuel Costs (¢ / kWh)	2.92	2.69	0.23	8.55%
TOTAL				
Total Dollar	283,358,360	261,680,218	21,678,142	8.28%
BTUs Burned	85,957,268	82,737,320	3,219,948	3.89%
$/mmBtu	3.297	3.16	0.134	4.23%
Generation (MWh)	9,296,747	8,986,155	310,592	3.46%
Fuel Costs (¢ / kWh)	3.05	2.91	0.14	4.81%

Note:
(1) - Revised E1-b submitted 8/24/2018. Amounts reflect actuals through July 2018

Schedule 3

GULF POWER COMPANY
2018 Natural Gas Hedging Results

	Actual Gas Burn for Generation MMBtu *	Hedged Volume of Gas Burn MMBtu	Gulf Hedge Settlement Cost ($)
Jan-18	5,291,141	1,420,000	1,503,140
Feb-18	4,653,288	1,420,000	235,080
Mar-18	5,359,843	1,420,000	1,643,720
Apr-18	3,415,729	1,420,000	1,569,880
May-18	2,973,393	1,420,000	1,385,280
Jun-18	5,542,334	1,420,000	1,308,600
Jul-18	6,523,665	1,420,000	1,136,780
Aug-18	6,184,353	1,420,000	1,383,860
Sep-18	6,697,968	1,420,000	1,280,200
Oct-18	2,846,997	1,420,000	989,160
Nov-18	4,449,440	1,420,000	631,600
Dec-18	5,595,576	1,420,000	(1,235,000)
TOTAL	**59,533,727**	**17,040,000**	**$ 11,832,300**
	Annual Hedge Ratio:	**29%**	

* 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 4

GULF POWER COMPANY
CAPACITY VARIANCES SUMMARY
ACTUAL vs. ESTIMATED
FOR THE PERIOD
JANUARY 2018 THROUGH DECEMBER 2018

		2018 Final True-Up	2018 Actual/ Estimated	Difference	Percent Variance
1	IIC Payments / (Receipts) ($)	(44,206)	(3,527)	(40,679)	1153.37%
2	Other Capacity Payments / (Receipts)	85,454,245	85,416,023	38,222	0.04%
3	Transmission Revenue ($)	(187,773)	(139,180)	(48,593)	34.91%
4	Scherer/Flint Credit	(8,783,435)	(8,955,368)	171,933	-1.92%
5	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) ($)	76,438,831	76,317,948	120,882	0.16%
6	Jurisdictional %	0.9718277	0.9718277	-	0.00%
7	Total Jurisdictional Recovery Amount (Line 5 * 6) ($)	74,285,373	74,167,896	117,477	0.16%
8	Jurisdictional Capacity Cost Recovery Revenues Net of Taxes ($)	79,008,301	78,512,587	495,714	0.63%
9	True-Up Provision ($)	(3,152,586)	(3,152,586)	0	0.00%
10	Jurisdictional Capacity Cost Recovery Revenue (Line 8 + 9) ($)	75,855,715	75,360,001	495,714	0.66%
11	Over/(Under) Recovery (Line 10 - 7) ($)	1,570,342	1,192,104	378,238	31.73%
12	Interest Provision ($)	2,049	(4,511)	6,560	-145.42%
13	Beginning Balance True-Up & Interest Provision ($)	(2,306,169)	(2,306,169)	0	0.00%
14	True-Up Collected/(Refunded) ($)	3,152,586	3,152,586	0	0.00%
15	Adjustment	0	0	0	0.00%
	End of Period Total Net True-Up (Lines 11 + 12 + 13 + 14) ($)	2,418,808	2,034,010	384,798	18.92%

SCHEDULE CCA-1

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2018 - DECEMBER 2018

1. Estimated over/(under)-recovery for the period January 2018 - December 2018 (Schedule CCE-1a, line 1, filed July 27, 2018 and approved in FPSC Order No. PSC-2018-0610-FOF-EI issued on December 26, 2018)	$	1,187,593
2. Actual over/(under)-recovery for the period January 2018 - December 2018 (Schedule CCA-2, Line 11 + 12 + 15)		1,572,391
3. Amount to be refunded/(recovered) in the January 2020 - December 2020 projection period (Line 2 - Line 1)	$	384,798

SCHEDULE CCA-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2018 - DECEMBER 2018

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1.	IIC Payments / (Receipts) ($)	(1,649)	(3,026)	(3,026)	1,036	6,164	(3,026)	(3,026)	(1,649)	(18,279)	(11,670)	(3,026)	(3,026)	(44,206)
2.	Other Capacity Payments / (Receipts)	7,197,284	7,197,284	7,197,284	7,197,284	6,359,064	7,197,284	7,184,794	7,184,793	7,184,794	7,184,794	7,184,794	7,184,794	85,454,245
3.	Transmission Revenue ($)	(22,631)	(13,447)	(20,829)	(15,900)	3,348	(16,721)	(14,636)	(14,126)	(14,958)	(15,508)	(30,343)	(12,022)	(187,773)
4.	Scherer/Flint Credit	(727,585)	(748,004)	(744,943)	(716,012)	(685,746)	(702,832)	(786,380)	(754,297)	(739,734)	(766,195)	(726,649)	(685,057)	(8,783,435)
5.	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) ($)	6,445,419	6,432,807	6,428,486	6,466,408	5,682,829	6,474,704	6,380,751	6,414,720	6,411,823	6,391,421	6,424,776	6,484,688	76,438,831
6.	Jurisdictional %	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
7.	Total Jurisdictional Recovery Amount (Line 5 * 6) ($)	6,263,837	6,251,580	6,247,381	6,284,234	5,522,730	6,292,297	6,200,991	6,234,002	6,231,187	6,211,360	6,243,775	6,301,999	74,285,373
8.	Jurisdictional Capacity Cost Recovery Revenues Net of Taxes ($)	7,515,518	4,881,451	5,145,153	5,107,936	6,924,168	7,960,642	8,560,610	8,004,964	7,725,408	6,271,230	5,380,317	5,530,904	79,008,301
9.	True-Up Provision ($)	(262,710)	(262,716)	(262,716)	(262,716)	(262,716)	(262,716)	(262,716)	(262,716)	(262,716)	(262,716)	(262,716)	(262,716)	(3,152,586)
10.	Jurisdictional Capacity Cost Recovery Revenue (Line 8 + 9) ($)	7,252,808	4,618,735	4,882,437	4,845,220	6,661,452	7,697,926	8,297,894	7,742,248	7,462,692	6,008,514	5,117,601	5,268,188	75,855,715
11.	Over/(Under) Recovery (Line 10 - 7) ($)	988,971	(1,632,845)	(1,364,944)	(1,439,014)	1,138,722	1,405,629	2,096,903	1,508,246	1,231,505	(202,846)	(1,126,174)	(1,033,811)	1,570,342
12.	Interest Provision ($)	(2,129)	(2,235)	(4,321)	(6,375)	(6,211)	(3,982)	(790)	2,616	5,624	7,475	6,872	5,505	2,049
13.	Beginning Balance True-Up & Interest Provision ($)	(2,306,169)	(1,056,617)	(2,428,981)	(3,535,530)	(4,718,203)	(3,322,976)	(1,658,613)	700,216	2,473,794	3,973,639	4,040,984	3,184,398	(2,306,169)
14.	True-Up Collected/(Refunded) ($)	262,710	262,716	262,716	262,716	262,716	262,716	262,716	262,716	262,716	262,716	262,716	262,716	3,152,586
15.	Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
16.	End of Period Total Net True-Up (Lines 11 + 12 + 13 + 14 + 15) ($)	(1,056,617)	(2,428,981)	(3,535,530)	(4,718,203)	(3,322,976)	(1,658,613)	700,216	2,473,794	3,973,639	4,040,984	3,184,398	2,418,808	2,418,808
	Average Monthly Interest Rate	0.1267%	0.1283%	0.1450%	0.1546%	0.1546%	0.1600%	0.1650%	0.1650%	0.1746%	0.1867%	0.1904%	0.1967%	
	Commercial Paper Annual Rate 0.72%	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	1.98%	1.98%	2.21%	2.27%	2.30%	2.42%	
	Average Annual Rate	1.52%	1.54%	1.74%	1.86%	1.86%	1.92%	1.98%	1.98%	2.10%	2.24%	2.29%	2.36%	

SCHEDULE CCA-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2018 - DECEMBER 2018

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. Beginning True-Up Amount ($)	(2,306,169)	(1,056,617)	(2,428,981)	(3,535,530)	(4,718,203)	(3,322,976)	(1,658,613)	700,216	2,473,794	3,973,639	4,040,984	3,184,398	
2. Ending True-Up Amount Before Interest ($)	(1,054,488)	(2,426,746)	(3,531,209)	(4,711,828)	(3,316,765)	(1,654,631)	701,006	2,471,178	3,968,015	4,033,509	3,177,526	2,413,303	
3. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	(3,360,657)	(3,483,363)	(5,960,190)	(8,247,358)	(8,034,968)	(4,977,607)	(957,607)	3,171,394	6,441,809	8,007,148	7,218,510	5,597,701	
4. Average True-Up Amount ($)	(1,680,329)	(1,741,682)	(2,980,095)	(4,123,679)	(4,017,484)	(2,488,804)	(478,804)	1,585,697	3,220,905	4,003,574	3,609,255	2,798,851	
5. Interest Rate - First Day of Reporting Business Month	1.58%	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	1.98%	1.98%	2.21%	2.27%	2.30%	
6. Interest Rate - First Day of Subsequent Business Month	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	1.98%	1.98%	2.21%	2.27%	2.30%	2.42%	
7. Total Interest Rate (Lines 5 + 6)	3.04%	3.08%	3.48%	3.71%	3.71%	3.84%	3.96%	3.96%	4.19%	4.48%	4.57%	4.72%	
8. Average Interest Rate	1.520%	1.540%	1.740%	1.855%	1.855%	1.920%	1.980%	1.980%	2.095%	2.240%	2.285%	2.360%	
9. Monthly Average Interest Rate (1/12 Of Line 8)	0.1267%	0.1283%	0.1450%	0.1546%	0.1546%	0.1600%	0.1650%	0.1650%	0.1746%	0.1867%	0.1904%	0.1967%	
10. Interest Provision For the Month (Lines 4 X 9) ($)	(2,129)	(2,235)	(4,321)	(6,375)	(6,211)	(3,982)	(790)	2,616	5,624	7,475	6,872	5,505	2,049

SCHEDULE CCA-4

Gulf Power Company
2018 Capacity Contracts

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		Term		Contract									
1	**Contract/Counterparty**	**Start**	**End [1]**	**Type**									
2	Southern Intercompany Interchange	**5/1/2007**	**5 Yr Notice**	**SES Opco**									
3	*PPAs*												
4	Shell Energy N.A. (U.S.), LP	**11/2/2009**	**5/31/2023**	**Firm**									
5	*Other*												
6	South Carolina PSA	**9/1/2003**	**-**	**Other**									
7	Exelon Corporation	**1/2/2018**	**8/31/2018**	**Other**									
8	PowerSouth Energy Cooperative	**9/15/2018**	**10/12/2018**	**Other**									

	Capacity Costs ($)	**January**	**February**	**March**	**April [2]**	**May [2]**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
9														
10	Southern Intercompany Interchange	0	0	0	4,062	9,190	0	0	0	0	0	0	0	13,252
11	*PPAs*													
12	Shell Energy N.A. (U.S.), LP	[redacted]												
13														
14	*Other*													
15	South Carolina PSA													
16	Exelon Corporation													
17	PowerSouth Energy Cooperative													
18	Total													

	Capacity MW	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
19													
20	Southern Intercompany Interchange	0.0	0.0	0.0	37.2	83.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	*PPAs*												
22	Shell Energy N.A. (U.S.), LP	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0
23													
24	*Other*												
25	South Carolina PSA	[redacted]											
26	Exelon Corporation												
27	PowerSouth Energy Cooperative												

28 (1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
29 (2) Southern Intercompany Interchange reserve sharing prior month true up only.

Gulf Power

January 22, 2019

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

Re: Docket No. 20190001-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 2018 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,

C. Shane Boyett

C. Shane Boyett
Regulatory Issues Manager

md

Attachment

cc w/attachment: Florida Public Service Commission
Michael C. Barrett
Division of Auditing and Safety
Lynn Deamer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 53
PARTY: GULF POWER – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-2

bc w/attachment: H. Bell
S. Boyett
M. Goldstein
H. Henderson
C. Howton
C. Nicholson
C. Rivera
L. Roddy
J. Van Norman
M. Young

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20180001-EI

MONTHLY FUEL FILING

December 2018

Gulf Power

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2018

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	28,981,534	24,826,792	4,154,742	16.73	866,632,649	883,812,000	(17,179,351)	(1.94)	3.3442	2.8091	0.54	19.05
1a	Hedging Settlement Costs (A2)	(1,235,000)	979,300	(2,214,300)	(226.11)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
1b	Scherer/Flint Credit	(553,681)	(523,109)	(30,571)	5.84	(18,637,223)	(20,000,000)	1,362,777	(6.81)	0.0000	0.0000	0.00	0.00
2	Adjustments to Fuel Cost (A2, Page 1) **	606	0	606	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	TOTAL COST OF GENERATED POWER	27,193,459	25,282,983	1,910,477	7.56	847,995,426	863,812,000	(15,816,574)	(1.83)	3.2068	2.9269	0.28	9.56
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)	18,295,868	14,499,206	3,796,662	26.19	512,381,251	479,045,000	33,336,251	6.96	3.5708	3.0267	0.54	17.98
6	Energy Payments to Qualifying Facilities (A8)	850,295	0	850,295	100.00	24,556,880	0	24,556,880	100.00	3.4626	0.0000	3.46	0.00
7	TOTAL COST OF PURCHASED POWER	19,146,163	14,499,206	4,646,957	32.05	536,938,131	479,045,000	57,893,131	12.09	3.5658	3.0267	0.54	17.81
8	Total Available KWH (Line 3 + Line 7)	46,339,623	39,782,189	6,557,434	16.48	1,384,933,557	1,342,857,000	42,076,557	3.13				
9	Fuel Cost of Economy Sales (A6)	(126,286)	(237,099)	110,813	(46.74)	(4,217,081)	(10,570,365)	6,353,284	(60.10)	(2.9946)	(2.2431)	(0.75)	(33.50)
10	Gain on Economy Sales (A6)	(3,523)	(9,000)	5,477	(60.86)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
11	Fuel Cost of Other Power Sales (A6)	(18,149,652)	(10,025,923)	(8,123,729)	81.03	(497,506,487)	(450,199,259)	(47,307,228)	10.51	(3.6481)	(2.2270)	(1.42)	(63.81)
12	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 9 + 10 + 11)	(18,279,461)	(10,272,023)	(8,007,439)	77.95	(501,723,568)	(460,769,624)	(40,953,944)	8.89	(3.6433)	(2.2293)	(1.41)	(63.43)
13	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 3 + 7 + 12)	28,060,161	29,510,166	(1,450,005)	(4.91)	883,209,989	882,087,376	1,122,613	0.13	3.1771	3.3455	(0.17)	(5.03)
14	Company Use *	37,715	42,755	(5,040)	(11.79)	1,187,085	1,278,000	(90,915)	(7.11)	3.1771	3.3455	(0.17)	(5.03)
15	T & D Losses *	1,720,050	1,453,666	266,384	18.32	54,139,003	43,451,376	10,687,627	24.60	3.1771	3.3455	(0.17)	(5.03)
16	TERRITORIAL KWH SALES	28,060,161	29,510,166	(1,450,005)	(4.91)	827,883,901	837,358,000	(9,474,099)	(1.13)	3.3894	3.5242	(0.13)	(3.82)
17	Wholesale KWH Sales	776,509	885,098	(108,589)	(12.27)	22,909,834	25,115,000	(2,205,166)	(8.78)	3.3894	3.5242	(0.13)	(3.82)
18	Jurisdictional KWH Sales	27,283,652	28,625,068	(1,341,416)	(4.69)	804,974,067	812,243,000	(7,268,933)	(0.89)	3.3894	3.5242	(0.13)	(3.82)
19	Jurisdictional Loss Multiplier	1.0012	1.0012							1.0012	1.0012		
20	Jurisdictional KWH Sales Adj. for Line Losses	27,316,392	28,659,418	(1,343,026)	(4.69)	804,974,067	812,243,000	(7,268,933)	(0.89)	3.3934	3.5284	(0.14)	(3.83)
21	TRUE-UP	2,720,897	2,720,897	0	0.00	804,974,067	812,243,000	(7,268,933)	(0.89)	0.3380	0.3350	0.00	0.90
22	TOTAL JURISDICTIONAL FUEL COST	30,037,289	31,380,315	(1,343,026)	(4.28)	804,974,067	812,243,000	(7,268,933)	(0.89)	3.7314	3.8634	(0.13)	(3.42)
23	Revenue Tax Factor									1.00072	1.00072		
24	Fuel Factor Adjusted for Revenue Taxes									3.7341	3.8662	(0.13)	(3.42)
25	GPIF Reward / (Penalty)	(170,269)	(170,269)	0	0.00	804,974,067	812,243,000	(7,268,933)	(0.89)	(0.0212)	(0.0210)	(0.00)	0.95
26	Tax Savings Credit	(4,069,371)	(4,069,371)	0	0.00	804,974,067	812,243,000	(7,268,933)	(0.89)	(0.5055)	(0.5010)	(0.00)	0.90
27	Fuel Factor Adjusted for GPIF Reward / (Penalty) & Tax Savings Credit									3.2074	3.3442	(0.14)	(4.09)
28	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.207	3.344		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

I

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: DECEMBER 2018

LINE	DESCRIPTION	REFERENCE		AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3	$	28,981,534
2	Scherer/Flint Credit	Schedule A-3, Line 2b	$	(553,681)
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	$	606
4	Hedging Settlement Costs	Schedule A-2, Line A-5	$	(1,235,000)
5	Fuel Cost of Purchased Power	Schedule A-7	$	-
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	$	18,295,868
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	$	-
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 6	$	850,295
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7	$	(18,279,461)
10	Total Fuel and Net Power Transactions		$	28,060,161

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2018
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	291,592,513	279,327,057	12,265,456	4.39	9,587,921,000	9,461,799,000	126,122,000	1.33	3.0412	2.9522	0.09	3.01
1a	Hedging Settlement Costs (A2)	11,832,300	13,673,280	(1,840,980)	(13.46)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
1b	Scherer/Flint Credit	(7,434,492)	(7,987,663)	553,171	(6.93)	(267,882,894)	(309,026,000)	41,143,106	(13.31)	0.0000	0.0000	0.00	0.00
2	Adjustments to Fuel Cost (A2, Page 1) **	(27,748)	0	(27,748)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	TOTAL COST OF GENERATED POWER	295,962,573	285,012,674	10,949,899	3.84	9,320,038,106	9,152,773,000	167,265,106	1.83	3.1756	3.1139	0.06	1.98
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)	204,964,275.83	203,034,625	1,929,651	0.95	6,238,804,763	6,499,023,000	(260,218,237)	(4.00)	3.2853	3.1241	0.16	5.16
6	Energy Payments to Qualifying Facilities (A8)	6,935,151.74	0	6,935,152	100.00	193,742,587	0	193,742,587	100.00	3.5796	0.0000	3.58	0.00
7	TOTAL COST OF PURCHASED POWER	211,899,428	203,034,625	8,864,803	4.37	6,432,547,350	6,499,023,000	(66,475,650)	(1.02)	3.2942	3.1241	0.17	5.44
8	Total Available KWH (Line 3 + Line 7)	507,862,001	488,047,298	19,814,702	4.06	15,752,585,456	15,651,796,000	100,789,456	0.64				
9	Fuel Cost of Economy Sales (A6)	(3,010,246)	(2,574,010)	(436,236)	16.95	(94,349,315)	(101,663,644)	7,314,329	(7.19)	(3.1905)	(2.5319)	(0.66)	(26.01)
10	Gain on Economy Sales (A6)	(589,409)	(177,000)	(412,409)	233.00	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
11	Fuel Cost of Other Power Sales (A6)	(119,604,412)	(95,648,532)	(23,955,880)	25.05	(3,607,354,409)	(3,836,921,721)	229,567,312	(5.98)	(3.3156)	(2.4928)	(0.82)	(33.01)
12	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 9 + 10 + 11)	(123,204,069)	(98,399,542)	(24,804,525)	25.21	(3,701,703,724)	(3,938,585,365)	236,881,641	(6.01)	(3.3283)	(2.4983)	(0.83)	(33.22)
13	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 3 + 7 + 12)	384,657,932.75	389,647,756	(4,989,824)	(1.28)	12,050,881,731	11,713,210,635	337,671,096	2.88	3.1919	3.3266	(0.13)	(4.05)
14	Company Use *	442,722	525,719	(82,997)	(15.79)	13,870,160	15,803,500	(1,933,340)	(12.23)	3.1919	3.3266	(0.13)	(4.05)
15	T & D Losses *	19,410,048	19,208,292	201,756	1.05	608,103,266	577,415,135	30,688,131	5.31	3.1919	3.3266	(0.13)	(4.05)
16	TERRITORIAL KWH SALES	384,657,934	389,647,756	(4,989,822)	(1.28)	11,428,908,305	11,119,992,000	308,916,305	2.78	3.3657	3.5040	(0.14)	(3.95)
17	Wholesale KWH Sales	9,944,754	11,066,810	(1,122,056)	(10.14)	296,525,388	315,349,000	(18,823,612)	(5.97)	3.3538	3.5094	(0.16)	(4.43)
18	Jurisdictional KWH Sales	374,713,180	378,580,946	(3,867,766)	(1.02)	11,132,382,917	10,804,643,000	327,739,917	3.03	3.3660	3.5039	(0.14)	(3.94)
19	Jurisdictional Loss Multiplier	1.0012	1.0012							1.0012	1.0012		
20	Jurisdictional KWH Sales Adj. for Line Losses	375,162,835	379,035,243	(3,872,408)	(1.02)	11,132,382,917	10,804,643,000	327,739,917	3.03	3.3700	3.5081	(0.14)	(3.94)
21	TRUE-UP	32,650,765	32,650,765	0	0.00	11,132,382,917	10,804,643,000	327,739,917	3.03	0.2933	0.3022	(0.01)	(2.95)
22	TOTAL JURISDICTIONAL FUEL COST	407,813,600	411,686,008	(3,872,408)	(0.94)	11,132,382,917	10,804,643,000	327,739,917	3.03	3.6633	3.8103	(0.15)	(3.86)
23	Revenue Tax Factor									1.00072	1.00072		
24	Fuel Factor Adjusted for Revenue Taxes									3.6659	3.8130	(0.15)	(3.86)
25	GPIF Reward / (Penalty)	(2,043,225)	(2,043,225)	0	0.00	11,132,382,917	10,804,643,000	327,739,917	3.03	(0.0184)	(0.0189)	0.00	(2.65)
26	Tax Savings Credit	(73,247,667)	(73,247,667)	0	0.00	11,132,382,917	10,804,643,000	327,739,917	3.03	(0.6580)	(0.6779)	0.02	(2.94)
27	Fuel Factor Adjusted for GPIF Reward / (Penalty) & Tax Savings Credit									2.9895	3.1162	(0.13)	(4.07)
28	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.990	3.116		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

		CURRENT MONTH				PERIOD - TO - DATE			
				$ *DIFFERENCE*				$ *DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	28,781,426.61	24,668,471	4,112,955.61	16.67	289,224,643.20	276,761,880	12,462,762.80	4.50
1a	Other Generation	200,107.65	158,321	41,786.65	26.39	2,367,869.87	2,565,177	(197,307.13)	(7.69)
1b	Scherer/Flint Credit	(553,680.71)	(523,109)	(30,571.23)	5.84	(7,434,491.83)	(7,987,663)	553,171.29	(6.93)
2	Fuel Cost of Power Sold	(18,279,461.55)	(10,272,023)	(8,007,438.55)	(77.95)	(123,204,068.87)	(98,399,543)	(24,804,525.87)	(25.21)
3	Fuel Cost - Purchased Power	18,295,868.47	14,499,206	3,796,662.12	26.19	204,964,275.83	203,034,625	1,929,651.22	0.95
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	850,294.75	0	850,294.75	100.00	6,935,151.38	0	6,935,151.38	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	(1,235,000.00)	979,300	(2,214,300.00)	(226.11)	11,832,300.00	13,673,280	(1,840,980.00)	(13.46)
6	Total Fuel & Net Power Transactions	28,059,555.22	29,510,166	(1,450,610.65)	(4.92)	384,685,679.58	389,647,756	(4,962,076.31)	(1.27)
7	AdjustmentsTo Fuel Cost*	605.66	0.000	605.66	100.00	(27,746.64)	0	(27,746.64)	100.00
8	Adj. Total Fuel & Net Power Transactions	28,060,160.88	29,510,166	(1,450,004.99)	(4.91)	384,657,932.94	389,647,756	(4,989,822.95)	(1.28)
B.	*KWH Sales*								
1	Jurisdictional Sales	804,974,067	812,243,000	(7,268,933)	(0.89)	11,132,382,917	10,804,643,000	327,739,917	3.03
2	Non-Jurisdictional Sales	22,909,834	25,115,000	(2,205,166)	(8.78)	296,525,388	315,349,000	(18,823,612)	(5.97)
3	Total Territorial Sales	827,883,901	837,358,000	(9,474,099)	(1.13)	11,428,908,305	11,119,992,000	308,916,305	2.78
4	Juris. Sales as % of Total Terr. Sales	97.2327	97.0007	0.2320	0.24	97.4055	97.1641	0.2414	0.25

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	23,977,039.21	23,805,947	171,092.30	0.72	350,111,656.85	336,738,435	13,373,222.21	3.97
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(2,720,897.00)	(2,720,897)	0.00	0.00	(32,650,765.00)	(32,650,765)	0.00	0.00
2b	Incentive Provision	170,146.00	170,146	0.00	0.00	2,041,755.00	2,041,755	0.00	0.00
2c	Tax Savings Credit	4,066,593.00	4,066,593	0.00	0.00	73,198,667.00	73,198,667	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	25,492,881.21	25,321,789	171,092.21	0.68	392,701,313.85	379,328,092	13,373,221.85	3.53
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	28,060,160.88	29,510,166	(1,450,004.99)	(4.91)	384,657,933.22	389,647,755	(4,989,822.27)	(1.28)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.2327	97.0007	0.2320	0.24	97.4055	97.1641	0.2414	0.25
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0012)	27,316,392.43	28,659,418	(1,343,025.57)	(4.69)	375,162,834.76	379,035,243	(3,872,408.24)	(1.02)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(1,823,511.22)	(3,337,629)	1,514,117.78	45.37	17,538,479.09	292,851	17,245,628.09	(5,888.87)
8	Interest Provision for the Month	53,932.75	647	53,285.75	(8,235.82)	169,148.96	(271,684)	440,832.96	162.26
9	Beginning True-Up & Interest Provision	26,970,091.06	637,252	26,332,839.06	(4,132.25)	(22,436,983.46)	(32,650,765)	10,213,781.54	31.28
10	True-Up Collected / (Refunded)	2,720,897.00	2,720,897	0.00	0.00	32,650,765.00	32,650,765	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	27,921,409.59	21,167	27,900,242.59	(131,810.09)	27,921,409.59	21,167	27,900,242.59	(131,810.09)
12	Adjustment		0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	27,921,409.59	21,167	27,900,242.59	(131,810.09)	27,921,409.59	21,167	27,900,242.59	(131,810.09)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	**ESTIMATED**	**AMOUNT ($)**	**%**
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	26,970,091.06	637,252	26,332,839.06	4,132.25
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	27,867,476.84	20,520	27,846,956.84	135,706.42
3	Total of Beginning & Ending True-Up Amts.	54,837,567.90	657,772	54,179,795.90	8,236.87
4	Average True-Up Amount	27,418,783.95	328,886	27,089,897.95	8,236.87
	Interest Rate				
5	1st Day of Reporting Business Month	2.30	2.30	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	2.42	2.42	0.0000	
7	Total (D5+D6)	4.72	4.72	0.0000	
8	Annual Average Interest Rate	2.36	2.36	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.1967	0.1967	0.0000	
10	Interest Provision (D4*D9)	53,932.75	647	53,285.75	8,235.82
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0012	1.0012		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	247,044	114,059	132,985	116.59	2,453,371	1,026,157	1,427,214	139.08
2	COAL	13,361,422	13,170,826	190,596	1.45	136,197,882	128,621,359	7,576,523	5.89
2a	Coal at Scherer	2,260,733	2,197,939	62,794	2.86	30,969,789	33,414,539	(2,444,750)	(7.32)
2b	Scherer/Flint Credit	(553,681)	(523,109)	(30,571)	5.84	(7,434,492)	(7,987,663)	553,171	(6.93)
3	GAS	12,932,185	9,206,623	3,725,562	40.47	117,849,813	112,949,969	4,899,844	4.34
4	GAS (B.L.)	107,081	67,536	39,545	58.55	3,061,476	2,390,326	671,150	28.08
5	LANDFILL GAS	68,769	69,809	(1,040)	(1.49)	799,662	828,965	(29,303)	(3.53)
6	OIL - C.T.	4,301	0	4,301	100.00	260,522	151,269	109,253	72.22
7	TOTAL ($)	28,427,854	24,303,683	4,124,171	16.97	284,158,020	271,339,394	12,818,626	4.72
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	410,733	417,060	(6,327)	(1.52)	4,405,881	4,097,429	308,452	7.53
9a	Coal at Scherer	77,596	84,033	(6,437)	(7.66)	1,120,484	1,292,684	(172,201)	(13.32)
9b	Scherer/Flint Credit	(18,637)	(20,000)	1,363	(6.82)	(267,883)	(309,026)	41,143	(13.31)
10	GAS	376,365	380,622	(4,257)	(1.12)	4,037,196	4,046,567	(9,371)	(0.23)
11	LANDFILL GAS	1,935	2,097	(162)	(7.73)	23,291	24,699	(1,408)	(5.70)
12	OIL - C.T.	3	0	3	100.00	1,069	420	649	154.52
13	TOTAL (MWH)	847,995	863,812	(15,817)	(1.83)	9,320,038	9,152,773	167,265	1.83
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	2,674	1,190	1,484	124.69	26,958	12,444	14,514	116.63
15	COAL (TONS)	211,531	217,184	(5,653)	(2.60)	2,226,470	2,103,527	122,943	5.84
16	GAS (MCF) (1)	2,736,834	2,487,149	249,685	10.04	28,634,056	27,058,515	1,575,541	5.82
17	OIL - C.T. (BBL)	44	0	44	100.00	2,726	1,597	1,129	70.72
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	5,205,585	5,437,102	(231,517)	(4.26)	56,967,319	56,190,013	777,306	1.38
19	GAS - Generation (1)	2,774,181	2,536,892	237,289	9.35	28,974,096	27,499,685	1,474,411	5.36
20	OIL - C.T.	257	0	257	100.00	15,853	5,850	10,003	170.99
21	TOTAL (MMBTU)	7,980,023	7,973,994	6,029	0.08	85,957,268	83,695,548	2,261,720	2.70
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	55.39	55.70	(0.31)	(0.56)	56.41	55.52	0.89	1.60
24	GAS	44.38	44.06	0.32	0.73	43.33	44.21	(0.88)	(1.99)
25	LANDFILL GAS	0.23	0.24	(0.01)	(4.17)	0.25	0.27	(0.02)	(7.41)
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	88.39	95.83	(7.44)	(7.76)	90.28	82.46	7.82	9.48
29	COAL ($/TON)	63.17	60.64	2.53	4.17	61.17	61.15	0.02	0.03
30	GAS ($/MCF) (1)	4.69	3.67	1.02	27.79	4.14	4.17	(0.03)	(0.72)
31	OIL - C.T. ($/BBL)	97.75	0.00	97.75	100.00	95.57	94.75	0.82	0.87
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	2.96	2.76	0.20	7.25	2.90	2.80	0.10	3.57
33	GAS - Generation (1)	4.59	3.57	1.02	28.57	3.99	4.01	(0.02)	(0.50)
34	OIL - C.T.	16.74	0.00	16.74	100.00	16.43	25.86	(9.43)	(36.47)
35	TOTAL ($/MMBTU)	3.53	3.02	0.51	16.89	3.27	3.20	0.07	2.19
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,083	11,302	(219)	(1.94)	10,833	11,059	(226)	(2.04)
37	GAS - Generation (1)	7,505	6,767	738	10.91	7,310	6,935	375	5.41
38	OIL - C.T.	85,667	0	85,667	100.00	14,830	13,929	901	6.47
39	TOTAL (BTU/KWH)	9,507	9,315	192	2.06	9,320	9,251	69	0.75
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	3.28	3.12	0.16	5.13	3.14	3.10	0.04	1.29
41	GAS	3.44	2.42	1.02	42.15	2.92	2.79	0.13	4.66
42	LANDFILL GAS	3.55	3.33	0.22	6.61	3.43	3.36	0.07	2.08
43	OIL - C.T.	143.36	0.00	143.36	100.00	24.37	36.02	(11.65)	(32.34)
44	TOTAL (¢/KWH)	3.35	2.81	0.54	19.22	3.05	2.96	0.09	3.04

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

Line	(a) Plant/Unit		(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(21)	0.0	67.9	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	8,109	1,020	8,272	34,619	0.00	4.27
3									Gas-S	10,828	1,020	11,046	46,231		4.27
4									Oil-S	9	138,500	50	806		89.56
5	Crist 5		75	246	0.4	63.4	13.6	43,569	Coal	0	0	0	0	0.00	0.00
6				0					Gas-G	10,506	1,020	10,718	44,856	0.00	4.27
7									Gas-S	3,505	1,020	3,576	14,966		4.27
8									Oil-S	20	138,500	116	1,881		94.05
9	Crist 6		299	117,137	52.7	90.9	70.5	11,424	Coal	40,886	11,375	930,157	2,670,363	2.28	65.31
10				0					Gas-G	399,982	1,020	408,029	1,707,681	0.00	0.00
11									Gas-S	10,625	1,020	10,838	45,360		4.27
12									Oil-S	432	138,500	2,515	40,654		94.11
13	Crist 7		475	235,496	66.6	100.0	66.6	10,790	Coal	112,599	11,283	2,540,910	7,354,112	3.12	65.31
14				0					Gas-G	0	1,020	0	0	0.00	0.00
15									Gas-S	123	1,020	125	524		4.26
16									Oil-S	49	138,500	287	4,641		94.71
17	Smith 3		605	333,935	74.2	93.3	81.3	7,029	Gas-G	2,293,156	1,024	2,347,162	10,944,921	3.28	4.77
18	Smith A	(1)	40	3	0.0	67.6	15.0	85,640	Oil	44	138,500	257	4,301	143.37	97.75
19	Scherer 3	(2)	215	77,596	48.5	86.2	54.8	11,042	Coal		5,858	856,795	2,260,733	2.91	0.00
20									Oil	480	138,500	2,792	44,522	0.00	92.75
21	Scherer/Flint Credit		(52)	(18,637)	N/A	N/A	N/A	N/A	Coal		N/A	(205,787)	(542,987)	N/A	N/A
22									Oil	(115)	N/A	(671)	(10,693)	N/A	N/A
23	Other Generation			6,714									200,108	2.98	0.00
24	Perdido			1,935					Landfill Gas				68,769	3.55	0.00
25	Daniel 1	(3)	251	48,758	26.1	83.6	38.9	10,955	Coal	29,681	8,998	534,163	1,643,058	3.37	55.36
26									Oil-S	736	138,500	4,284	63,261		85.95
27	Daniel 2	(3)	251	44,834	24.0	83.7	34.1	11,335	Coal	28,365	8,959	508,207	1,570,180	3.50	55.36
28									Oil-S	1,063	138,500	6,181	91,279		85.87
29	Total		2,234	847,995	51.0	91.4	59.8	9,507				7,980,023	28,304,145	3.34	

Notes & Adjust.:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(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

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,022)	
	Crist Coal Additive	127,731	
	Recoverable Fuel	28,427,854	3.35

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2018 Final True-Up Filing
Exhibit CSB-2, Page 11 of 23

SCHEDULE A-5
PAGE 1 OF 2

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	2,484	1,193	1,291	108.21	28,606	12,239	16,367	133.73
3	UNIT COST ($/BBL)	82.26	100.19	(17.93)	(17.90)	92.83	85.70	7.13	8.32
4	AMOUNT ($)	204,333	119,525	84,808	70.95	2,655,541	1,048,808	1,606,733	153.20
5	*BURNED :*								
6	UNITS (BBL)	2,860	1,190	1,670	140.32	28,106	12,444	15,662	125.86
7	UNIT COST ($/BBL)	88.67	95.83	(7.16)	(7.47)	89.86	82.46	7.40	8.97
8	AMOUNT ($)	253,592	114,059	139,533	122.33	2,525,626	1,026,157	1,499,469	146.12
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	5,488	5,999	(511)	(8.52)	5,488	5,999	(511)	(8.52)
11	UNIT COST ($/BBL)	90.72	95.04	(4.32)	(5)	90.72	95.04	(4.32)	(4.55)
12	AMOUNT ($)	497,890	570,123	(72,233)	(12.67)	497,890	570,123	(72,233)	(12.67)
13	DAYS SUPPLY	N/A	N/A						
	COAL EXCLUDING PLANT SCHERER								
14	*PURCHASES :*								
15	UNITS (TONS)	227,697	217,790	9,907	4.55	2,213,930	2,150,141	63,789	2.97
16	UNIT COST ($/TON)	64.16	58.38	5.78	9.90	61.15	61.00	0.15	0.25
17	AMOUNT ($)	14,609,358	12,714,730	1,894,628	14.90	135,380,061	131,165,409	4,214,652	3.21
18	*BURNED :*								
19	UNITS (TONS)	211,531	217,184	(5,653)	(2.60)	2,226,470	2,103,527	122,943	5.84
20	UNIT COST ($/TON)	62.58	60.64	1.94	3.20	60.89	61.15	(0.26)	(0.43)
21	AMOUNT ($)	13,237,713	13,170,826	66,887	0.51	135,569,693	128,621,359	6,948,334	5.40
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	381,474	500,204	(118,730)	(23.74)	381,474	500,204	(118,730)	(23.74)
24	UNIT COST ($/TON)	58.10	54.10	4.00	7.39	58.10	54.10	4.00	7.39
25	AMOUNT ($)	22,162,899	27,058,997	(4,896,098)	(18.09)	22,162,899	27,058,997	(4,896,098)	(18.09)
26	DAYS SUPPLY	24	31	(7)	(22.58)				
	COAL AT PLANT SCHERER								
27	*PURCHASES :*								
28	UNITS (MMBTU)	878,511	949,048	(70,537)	(7.43)	10,446,156	12,554,823	(2,108,667)	(16.80)
29	UNIT COST ($/MMBTU)	2.49	2.45	0.04	1.63	2.58	2.44	0.14	5.74
30	AMOUNT ($)	2,185,214	2,320,724	(135,510)	(5.84)	26,909,276	30,634,844	(3,725,568)	(12.16)
31	*BURNED :*								
32	UNITS (MMBTU)	856,795	893,844	(37,049)	(4.14)	11,979,903	13,628,381	(1,648,478)	(12.10)
33	UNIT COST ($/MMBTU)	2.64	2.46	0.18	7.32	2.55	2.45	0.10	4.08
34	AMOUNT ($)	2,260,733	2,197,939	62,794	2.86	30,505,887	33,414,539	(2,908,652)	(8.70)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	1,963,375	2,189,486	(226,111)	(10.33)	1,963,375	2,189,486	(226,111)	(10.33)
37	UNIT COST ($/MMBTU)	2.64	2.49	0.15	6.02	2.64	2.49	0.15	6.02
38	AMOUNT ($)	5,180,107	5,459,098	(278,991)	(5.11)	5,180,107	5,459,098	(278,991)	(5.11)
39	DAYS SUPPLY	37	41	(4)	(9.76)				
	GAS	(Reported on a MMBTU and $ basis)							
40	*PURCHASES :*								
41	UNITS (MMBTU)	2,843,710	2,536,892	306,818	12.09	29,263,913	27,499,685	1,764,228	6.42
42	UNIT COST ($/MMBTU)	4.52	3.57	0.95	26.61	4.08	4.01	0.07	1.75
43	AMOUNT ($)	12,864,601	9,048,302	3,816,299	42.18	119,409,666	110,384,792	9,024,874	8.18
44	*BURNED :*								
45	UNITS (MMBTU)	2,799,766	2,536,892	262,874	10.36	29,243,474	27,499,685	1,743,789	6.34
46	UNIT COST ($/MMBTU)	4.59	3.57	1.02	28.57	4.04	4.01	0.03	0.75
47	AMOUNT ($)	12,839,158	9,048,302	3,790,856	41.90	118,228,417	110,384,792	7,843,625	7.11
48	*ENDING INVENTORY :*								
48	UNITS (MMBTU)	858,911	0	858,911	100.00	858,911	0	858,911	100.00
50	UNIT COST ($/MMBTU)	4.66	0.00	4.66	100.00	4.66	0.00	4.66	100.00
51	AMOUNT ($)	4,005,140	0	4,005,140	100.00	4,005,140	0	4,005,140	100.00

SCHEDULE A-5
PAGE 2 OF 2

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	OTHER - C.T. OIL								
52	*PURCHASES :*								
53	UNITS (BBL) *	0	0	0	0.00	3,552	739	2,813	380.85
54	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	99.16	97.66	2.00	2.05
55	AMOUNT ($)	0	0	0	0.00	352,199	72,130	280,069	388.28
56	*BURNED :*								
57	UNITS (BBL)	44	0	44	100.00	2,726	999	1,727	172.86
58	UNIT COST ($/BBL)	97.75	0.00	97.75	100.00	95.57	95.83	(0.26)	(0.27)
59	AMOUNT ($)	4,301	0	4,301	100.00	260,521	95,742	164,779	172.11
60	*ENDING INVENTORY :*								
61	UNITS (BBL)	7,463	7,037	426	6.05	7,463	7,037	426	6.05
62	UNIT COST ($/BBL)	97.38	95.20	2.18	2.29	97.38	95.20	2.18	2.29
63	AMOUNT ($)	726,723	669,928	56,795	8.48	726,723	669,928	56,795	8.48
64	HOURS SUPPLY	84	80	4	5.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

CURRENT MONTH

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) (5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(8) (5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		450,199,259	0	450,199,259	2.23	2.60	10,025,923	11,696,179
2	Various	Economy Sales	10,570,365	0	10,570,365	2.24	2.60	237,099	275,236
3		Gain on Econ. Sales	0	0	0	0.00	0.00	9,000	9,000
4	TOTAL ESTIMATED SALES		460,769,624	0	460,769,624	2.23	2.60	10,272,023	11,980,415
	ACTUAL								
5	Southern Company Interchange		501,723,568	0	501,723,568	3.64	3.94	18,272,065	19,744,827
6	A.E.C.	External	197,313	0	197,313	2.60	3.42	5,124	6,753
7	DUKE PWR	External	332,894	0	332,894	3.13	3.89	10,406	12,935
8	EAGLE EN	External	235,147	0	235,147	4.80	5.70	11,285	13,407
9	ENDURE	External	22,878	0	22,878	3.01	4.12	689	944
10	EXELON	External	408,908	0	408,908	3.77	3.48	15,398	14,214
11	FPC	External	174,015	0	174,015	2.75	3.95	4,786	6,866
12	FPL	External	0	0	0	0.00	0.00	0	0
13	MACQUARI	External	6,053	0	6,053	34.51	3.90	2,089	236
14	MERCURIA	External	0	0	0	0.00	0.00	3	0
15	MISO	External	836,922	0	836,922	2.35	3.02	19,657	25,274
16	MORGAN	External	170,566	0	170,566	3.23	4.18	5,506	7,123
17	NCEMC	External	2,421	0	2,421	3.14	3.50	76	85
18	NTE	External	0	0	0	0.00	0.00	0	0
19	OPC	External	149,078	0	149,078	4.07	4.39	6,062	6,541
20	ORLANDO	External	0	0	0	0.00	0.00	6	0
21	PJM	External	43,943	0	43,943	2.66	3.32	1,170	1,457
22	REMC	External	0	0	0	0.00	0.00	11	0
23	SCE&G	External	48,421	0	48,421	2.72	3.43	1,319	1,658
24	SEC	External	0	0	0	0.00	0.00	0	0
25	SEPA	External	0	0	0	0.00	0.00	0	0
26	TAL	External	0	0	0	0.00	0.00	0	0
27	TEA	External	1,363,967	0	1,363,967	2.64	3.35	36,058	45,680
28	TECO	External	6,053	0	6,053	4.81	6.40	291	387
29	TENASKA	External	0	0	0	0.00	0.00	0	0
30	TVA	External	145,262	0	145,262	2.88	3.70	4,186	5,369
31	WRI	External	73,240	0	73,240	2.96	4.28	2,164	3,132
32	Less: Flow-Thru Energy		(4,217,081)	0	(4,217,081)	2.90	2.90	(122,413)	(122,413)
33	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	3,523	3,523
34	TOTAL ACTUAL SALES		501,723,568	0	501,723,568	3.64	3.94	18,279,461	19,774,476
35	Difference in Amount		40,953,944	0	40,953,944	1.41	0.00	8,007,439	7,794,061
36	Difference in Percent		8.89	0	8.89	63.23	0.00	77.95	65.06

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 33

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

PERIOD TO DATE

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		3,836,921,721	0	3,836,921,721	2.49	2.89	95,648,531	110,786,187
2	Various	Economy Sales	101,663,644	0	101,663,644	2.53	2.92	2,574,010	2,970,563
3		Gain on Econ. Sales	0	0	0	0.00	0.00	177,000	177,000
4	TOTAL ESTIMATED SALES		3,938,585,365	0	3,938,585,365	2.50	2.89	98,399,542	113,933,750
	ACTUAL								
5	Southern Company Interchange		3,701,703,301	0	3,701,703,301	3.31	3.56	122,492,245	131,927,730
6	A.E.C.	External	8,171,634	0	8,171,634	3.12	3.80	255,280	310,698
7	DUKE PWR	External	3,836,578	0	3,836,578	3.66	6.34	140,365	243,348
8	EAGLE EN	External	3,663,242	0	3,663,242	3.06	4.10	112,050	150,301
9	ENDURE	External	964,626	0	964,626	3.00	4.18	28,958	40,322
10	EXELON	External	3,950,849	0	3,950,849	4.32	3.66	170,830	144,674
11	FPC	External	1,993,393	0	1,993,393	3.35	4.59	66,776	91,433
12	FPL	External	3,704,357	0	3,704,357	3.45	4.80	127,681	177,786
13	MACQUARI	External	2,311,218	0	2,311,218	3.95	3.66	91,216	84,690
14	MERCURIA	External	1,636,639	0	1,636,639	2.22	2.86	36,334	46,836
15	MISO	External	9,024,899	0	9,024,899	2.88	3.98	259,482	359,031
16	MORGAN	External	5,174,602	0	5,174,602	4.75	4.01	245,811	207,277
17	NCEMC	External	64,886	0	64,886	2.95	4.10	1,914	2,663
18	NTE	External	1,029	0	1,029	3.31	3.60	34	37
19	OPC	External	1,373,849	0	1,373,849	3.59	4.96	49,265	68,087
20	ORLANDO	External	863,514	0	863,514	3.12	4.45	26,971	38,396
21	PJM	External	2,566,760	0	2,566,760	2.91	4.64	74,631	119,188
22	REMC	External	828,466	0	828,466	2.75	3.90	22,795	32,298
23	SCE&G	External	724,513	0	724,513	3.44	5.71	24,910	41,373
24	SEC	External	3,026	0	3,026	0.00	4.04	0	122
25	SEPA	External	4,820,829	0	4,820,829	2.35	3.52	113,067	169,533
26	TAL	External	1,869,638	0	1,869,638	3.07	4.62	57,371	86,422
27	TEA	External	22,556,717	0	22,556,717	2.58	3.46	582,478	779,493
28	TECO	External	1,406,550	0	1,406,550	2.90	6.05	40,767	85,074
29	TENASKA	External	343,963	0	343,963	2.45	4.45	8,419	15,299
30	TVA	External	11,015,385	0	11,015,385	3.93	5.96	432,979	656,701
31	WRI	External	1,478,153	0	1,478,153	2.70	3.95	39,861	58,343
32	Less: Flow-Thru Energy		(94,348,892)	0	(94,348,892)	3.06	3.06	(2,887,833)	(2,887,833)
33	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	589,410	589,410
34	TOTAL ACTUAL SALES		3,701,703,724	0	3,701,703,724	3.33	3.59	123,204,069	133,049,323
35	Difference in Amount		(236,881,641)	0	(236,881,641)	0.83	0.70	24,804,527	19,115,574
36	Difference in Percent		(6.01)	0	(6.01)	33.20	24.22	25.21	16.78

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 33

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

CURRENT MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
ACTUAL								
1 Bay County/Engen, LLC	Contract	2,510,000	0	0	0	3.11	3.11	78,175
2 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	10,093
3 Ascend Performance Materials	COG 1	22,046,880	0	0	0	3.44	3.44	757,641
4 International Paper	COG 1	0	0	0	0	0.00	0.00	4,386
5 TOTAL		24,556,880	0	0	0	3.46	3.46	850,295

PERIOD-TO-DATE

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
ACTUAL								
1 Bay County/Engen, LLC	Contract	46,173,000	0	0	0	3.11	3.11	1,437,896
2 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	10,355
3 Ascend Performance Materials	COG 1	146,541,631	0	0	0	3.72	3.72	5,451,832
4 International Paper	COG 1	1,027,956	0	0	0	3.41	3.41	35,069
5 TOTAL		193,742,587	0	0	0	3.58	3.58	6,935,151

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SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2018

	(1)	CURRENT MONTH (2)	(3)	(4)	PERIOD - TO - DATE (5)	(6)	(7)
	PURCHASED FROM	TOTAL KWH PURCHASED	TRANS. COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.	TOTAL KWH PURCHASED	TRANS. COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	3,172,000	3.42	108,326	430,238,000	2.66	11,424,214
2	Economy Energy	5,216,000	1.49	77,881	57,064,000	2.86	1,629,411
3	Other Purchases	470,657,000	3.04	14,313,000	6,011,721,000	3.16	189,981,000
4	TOTAL ESTIMATED PURCHASES	479,045,000	3.03	14,499,206	6,499,023,000	3.12	203,034,625
	ACTUAL						
5	Southern Company Interchange	28,790,975	2.25	648,171.00	543,385,878	3.13	16,982,722
6	Non-Associated Companies	16,789,000	4.42	741,797.03	396,914,877	4.06	16,101,606
7	Purchased Power Agreements	382,324,000	3.58	13,684,011.00	4,113,920,000	3.03	124,698,437
8	Renewable Energy Purchase Agreements	85,299,072	3.92	3,345,894.46	1,258,010,910	3.99	50,132,726
9	Other Wheeled Energy	3,355,985	0.00	N/A	20,425,790	0.00	N/A
10	Other Transactions	39,300	0.00	7,270.00	496,200	0.00	146,625
11	Less: Flow-Thru Energy	(4,217,081)	3.11	(131,275.00)	(94,348,892)	3.28	(3,097,839)
12	TOTAL ACTUAL PURCHASES	512,381,251	3.57	18,295,868.49	6,238,804,763	3.29	204,964,276
13	Difference in Amount	33,336,251	0.54	3,796,662	(260,218,237)	0.17	1,929,651
14	Difference in Percent	6.96	17.82	26.19	(4.00)	5.45	0.95

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2018 CAPACITY CONTRACTS
GULF POWER COMPANY

Capacity Costs ($)

A.	CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	TERM End	January	February	March	April	May	June	July	August	September	October	November	December	YTD
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	4,062	9,190	0	0	0	0	0	0	0	13,252
2	Power Purchase Agreements & Other Confidential Agreements				7,195,635	7,194,258	7,194,258	7,194,258	6,356,037	7,194,258	7,181,768	7,183,145	7,166,515	7,173,124	7,181,768	7,181,768	85,396,792
				Total	7,195,635	7,194,258	7,194,258	7,198,320	6,365,227	7,194,258	7,181,768	7,183,145	7,166,515	7,173,124	7,181,768	7,181,768	85,410,044

Capacity Costs (MW)

B.	CONTRACT/COUNTERPARTY	TYPE	Start	End	January	February	March	April	May	June	July	August	September	October	November	December
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	Varies	Varies	Varies	37	84	Varies	0	0	0	0	0	
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	

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2018 A Schedule Acronym Definitions
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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

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.: **20190001-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by electronic mail this 22nd day of January, 2019 to the following:

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Schedule E-1A

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP

TO BE INCLUDED IN THE PERIOD JANUARY 2020 - DECEMBER 2020

(1) Line No.	(2) Description	(3) Total
1.	Estimated over/(under)-recovery for the period January 2019 - December 2019 (Sch. E-1B, Page 2, line C9)	$ (5,178,904)
2.	Final over/(under)-recovery for the period January 2018 - December 2018 (Exhibit CSB-1, Schedule 1, line 3)	$ 4,512,071
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in January 2020 - December 2020	$ (666,834)
4.	Jurisdictional kWh sales for the period January 2020 - December 2020	10,951,029,000
5.	True-Up Factor (Line 3/Line 4) x 100(¢/kWH)	0.0061

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 54
PARTY: GULF POWER – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-3

Schedule E-1B

GULF POWER COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

	(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 Projection	August Projection	September Projection	October Projection	November Projection	December Projection	Total Period
A	1	Fuel Cost of System Generation	23,179,762.07	10,379,345.74	19,124,590.38	16,011,423.76	22,744,884.73	21,829,691.65	32,355,942.00	33,932,386.00	28,876,538.00	26,477,294.00	16,096,467.00	20,688,685.00	271,697,010.33
	1a	Fuel Cost of Hedging Settlement	142,790.00	454,190.00	496,940.00	560,840.00	626,990.00	596,840.00	700,340.00	761,540.00	772,790.00	757,490.00	722,990.00	619,640.00	7,213,380.00
	1b	Scherer/Flint Credit	(511,810.14)	0.00	1,541.56	(376,161.34)	(655,819.50)	(513,522.52)	(763,107.73)	(738,824.35)	(627,971.57)	(527,931.36)	(415,019.64)	(599,952.54)	(5,728,579.13)
	2	Fuel Cost of Power Sold	(6,315,373.90)	(3,847,602.75)	(11,789,380.30)	(2,592,931.79)	(4,832,360.33)	(1,715,190.22)	(11,989,619.00)	(14,428,268.00)	(13,972,870.00)	(9,378,224.00)	(9,287,276.00)	(11,340,424.00)	(101,489,520.29)
	3	Fuel Cost of Purchased Power	13,982,321.47	13,445,845.38	18,678,300.26	14,107,961.11	17,941,515.70	18,094,689.47	18,326,343.00	18,449,475.00	17,874,387.00	12,677,788.00	18,593,413.00	17,905,853.00	200,077,892.39
	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	639,169.63	523,201.78	497,243.49	444,567.42	520,567.74	338,094.18	0.00	0.00	0.00	0.00	0.00	0.00	2,962,844.24
	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	177,352.92	149,457.86	237,961.29	190,881.88	171,705.71	158,454.96	156,204.00	156,204.00	151,173.00	156,204.00	151,173.00	156,204.00	2,012,976.62
	6	Adjustments to Fuel Cost	0.00	(311,628.74)	(248,867.42)	0.00	(6,380.84)	105,679.30	0.00	0.00	0.00	0.00	0.00	0.00	(461,197.70)
	7	TOTAL FUEL & NET POWER TRANSACTIONS	31,294,212.05	20,792,809.27	26,998,329.26	28,346,581.04	36,511,103.21	38,894,736.82	38,786,102.27	38,132,512.65	33,074,046.43	30,162,620.64	25,861,747.36	27,430,005.46	376,284,806.46
B	1	Jurisdictional kWh Sales	864,788,358	670,334,830	747,527,553	754,647,350	1,008,838,581	1,116,743,905	1,182,325,000	1,171,710,000	1,004,542,000	848,931,000	731,492,000	827,032,000	10,928,912,577
	2	Non-Jurisdictional kWh Sales	24,797,417	18,315,462	20,326,293	19,981,205	27,436,089	27,436,089	30,780,000	30,334,000	26,676,000	22,945,000	21,493,000	25,124,000	295,644,555
	3	TOTAL SALES (Lines B1 + B2)	889,585,775	688,650,292	767,853,846	774,628,555	1,036,274,670	1,144,179,994	1,213,105,000	1,202,044,000	1,031,218,000	871,876,000	752,985,000	852,156,000	11,224,557,132
	4	Jurisdictional % of Total Sales (Line B1/B3)	97.2125%	97.3404%	97.3528%	97.4205%	97.3524%	97.6021%	97.4627%	97.4765%	97.4132%	97.3683%	97.1456%	97.0517%	
C	1	Jurisdictional Fuel Recovery Revenue (1) (Net of Revenue Taxes)	25,873,403.53	19,672,728.02	22,537,774.01	22,548,788.96	30,354,039.24	34,011,265.87	35,798,672.46	35,477,269.37	30,415,723.28	25,704,102.35	22,148,260.85	25,041,040.05	329,583,067.98
	2	True-Up Provision	1,950,781.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	23,409,339.00
	2a	Incentive Provision	21,386.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	256,687.00
	2b	Retail Tax Savings Credit	674,592.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	8,095,082.00
	3	FUEL REVENUE APPLICABLE TO PERIOD	28,520,162.53	22,319,487.02	25,184,533.01	25,195,547.96	33,000,798.24	36,658,024.87	38,445,431.46	38,124,028.37	33,062,482.28	28,350,861.35	24,795,019.85	27,687,799.05	353,249,093.98
	4	Fuel & Net Power Transactions (Line A7)	31,294,212.05	20,792,809.27	26,998,329.26	28,346,581.04	36,511,103.21	38,894,736.82	38,786,102.27	38,132,512.65	33,074,046.43	30,162,620.64	25,861,747.36	27,430,005.46	$376,284,806.46
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0012)	30,458,392	20,264,091	26,315,170	27,648,519	35,587,089	38,007,634	37,847,344.88	37,214,842.98	32,257,149.18	29,404,073.55	25,153,697.90	26,653,232.15	$366,811,236.53
	6	Over/(Under) Recovery (Line C3-C5)	(1,938,229.62)	2,055,395.54	(1,130,636.83)	(2,452,971.48)	(2,586,290.32)	(1,349,609.55)	598,087	909,185	805,333	(1,053,212)	(358,678)	1,034,567	($5,467,060.54)
	7	Interest Provision	52,291.51	48,467.09	46,256.62	38,875.52	29,254.97	20,964.32	16,187	13,904	11,818	7,830	2,710	(403)	$288,156.30
	8	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	$0
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2019 - DECEMBER 2019**													($5,178,904.24)

* (Gain)/Loss on sales of natural gas and contract dispute litigation

Notes 1: Projected Revenues based on the current approved 2019 Fuel Factor excluding revenue taxes of: 3.0278 ¢/KWH

Schedule E-1B-1

GULF POWER COMPANY
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL COST RECOVERY FACTOR

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
		Dollars				kWh				¢/kWh			
Line No.	Description	Estimated Actual	Estimated Original	Difference Amount	Difference %	Estimated Actual	Estimated Original	Difference Amount	Difference %	Estimated Actual	Estimated Original	Difference Amount	Difference %
1	Fuel Cost of System Net Generation	271,697,010	256,848,474	14,848,536	5.78	9,045,489,480	8,888,872,000	156,617,480	1.76	3.0037	2.8896	0.1141	3.95
1a	Fuel Cost of Hedging Settlement	7,213,380	6,701,880	511,500	7.63	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1b	Scherer/Flint Credit	(5,728,579)	(5,587,895)	(140,684)	2.52	(200,390,000)	(209,718,000)	9,328,000	(4.45)	0.0000	2.6645	(2.6645)	(100.00)
2	Other Generation	2,012,977	2,390,125	(377,148)	(15.78)	73,609,520	81,352,000	(7,742,480)	(9.52)	2.7347	2.9380	(0.2033)	(6.92)
3	Adjustments to Fuel Cost	(461,198)	0	(461,198)	-	0	0	0	0	N/A	N/A	N/A	N/A
4	**Total Cost of Generated Power**	274,733,590	260,352,584	14,381,006	5.52	8,918,709,000	8,760,506,000	158,203,000	1.81	3.0804	2.9719	0.1085	3.65
5	Energy Cost of Other Economy Purchases (Nonbroker)	200,077,892	214,200,334	(14,122,442)	(6.59)	7,003,878,800	7,318,073,000	(314,194,200)	(4.29)	2.8567	2.9270	(0.0703)	(2.40)
6	Energy Payments to Qualifying Facilities	2,962,844	0	2,962,844	-	112,431,285	0	112,431,285	-	2.6352	0.0000	2.6352	100.00
7	**Total Cost of Purchased Power**	203,040,737	214,200,334	(11,159,597)	(5.21)	7,116,310,085	7,318,073,000	(201,762,915)	(2.76)	2.8532	2.9270	(0.0738)	(2.52)
8	**Total Available** (Line 4 + Line 7)	477,774,327	474,552,918	3,221,409	0.68	16,035,019,085	16,078,579,000	(43,559,915)	(0.27)	2.9796	2.9515	0.0281	0.95
9	Fuel Cost of Economy Sales	(2,118,112)	(2,762,145)	644,033	(23.32)	(84,540,224)	(109,939,000)	25,398,776	(23.10)	2.5054	2.5124	(0.0070)	(0.28)
10	Gain on Economy Sales	(123,369)	(104,000)	(19,369)	18.62	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	Fuel Cost of Other Power Sales	(99,248,038)	(102,387,084)	3,139,046	(3.07)	(4,128,033,058)	(4,307,932,000)	179,898,942	(4.18)	2.4042	2.3767	0.0275	1.16
12	**Total Gains on Power Sales**	(101,489,520)	(105,253,229)	3,763,710	(3.58)	(4,212,573,282)	(4,417,871,000)	205,297,718	(4.65)	2.4092	2.3824	0.0268	1.12
13	**Total Fuel & Net Power Transactions**	376,284,806	369,299,689	6,985,117	1.89	11,822,445,803	11,660,708,000	161,737,803	1.39	3.1828	3.1670	0.0158	0.50
14	Company Use *	447,036	490,410	(43,374)	(8.84)	14,045,371	15,485,000	(1,439,629)	(9.30)	3.1828	3.1670	0.0158	0.50
15	T & D Losses *	18,582,565	18,191,090	391,475	2.15	583,843,300	574,395,000	9,448,300	1.64	3.1828	3.1670	0.0158	0.50
16	TERRITORIAL (SYSTEM) SALES	376,284,806	369,299,689	6,985,117	1.89	11,224,557,132	11,070,828,000	153,729,132	1.39	3.3523	3.3358	0.0165	0.49
17	Wholesale Sales	9,910,997	10,049,464	(138,467)	(1.38)	295,644,555	301,261,000	(5,616,445)	(1.86)	3.3523	3.3358	0.0165	0.49
18	Jurisdictional Sales	366,373,809	359,250,225	7,123,584	1.98	10,928,912,577	10,769,567,000	159,345,577	1.48	3.3523	3.3358	0.0165	0.49
19	Jurisdictional Sales Adj. for Line Losses (Line 18 x 1.0012)	366,811,237	359,681,325	7,129,912	1.98	10,928,912,577	10,769,567,000	159,345,577	1.48	3.3563	3.3398	0.0165	0.49
20	TRUE-UP **	(23,409,339)	(23,409,339)	0	0.00	10,928,912,577	10,769,567,000	159,345,577	1.48	(0.2142)	(0.2174)	0.0032	(1.47)
21	TOTAL JURISDICTIONAL FUEL COST	343,401,898	336,271,986	7,129,912	2.12	10,928,912,577	10,769,567,000	159,345,577	1.48	3.1421	3.1224	0.0197	0.63
22	Fuel Factor Adjusted for Revenue Taxes									3.1444	3.1246	0.0197	0.63
23	GPIF Reward / (Penalty) **	(256,872)	(256,872)	0	0.00	10,928,912,577	10,769,567,000	159,345,577	1.48	(0.0024)	(0.0024)	0.0000	0.00
27	Tax Savings Credit	(8,095,082)	(9,946,000)	1,850,918	(18.61)	10,928,912,577	10,769,567,000	159,345,577	1.48	(0.0741)	(0.0924)	0.0183	19.81
28	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.0679	3.0298	0.0381	1.26
29	**FUEL FACTOR ROUNDED TO NEAREST .001(¢/kWh)**									3.0680	3.0300	0.0380	1.25

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

Schedule E-2

GULF POWER COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(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 Projection	August Projection	September Projection	October Projection	November Projection	December Projection	TOTAL
1	Fuel Cost of System Generation [1]	23,179,762	10,379,346	19,124,590	16,011,424	22,744,885	21,829,692	32,355,942	33,932,386	28,876,538	26,477,294	16,096,467	20,688,685	271,697,010
1a	Other Generation	177,353	149,458	237,961	190,882	171,706	158,455	156,204	156,204	151,173	156,204	151,173	156,204	2,012,977
1b	Scherer/Flint Credit	(511,810)	0	1,542	(376,161)	(655,820)	(513,523)	(763,108)	(738,824)	(627,972)	(527,931)	(415,020)	(599,953)	(5,728,579)
2	Fuel Cost of Power Sold	(6,315,374)	(3,847,603)	(11,789,380)	(2,592,932)	(4,832,360)	(1,715,190)	(11,989,619)	(14,428,268)	(13,972,870)	(9,378,224)	(9,287,276)	(11,340,424)	(101,489,520)
3	Fuel Cost of Purchased Power	13,982,321	13,445,846	18,678,301	14,107,961	17,941,515	18,094,689	18,326,343	18,449,475	17,874,387	12,677,788	18,593,413	17,905,853	200,077,892
3a	Demand & Non-Fuel Cost of Pur Power	0	0	0	0	0	0	0	0	0	0	0	0	0
3b	Qualifying Facilities	639,170	523,202	497,244	444,567	520,568	338,094	0	0	0	0	0	0	2,962,844
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Hedging Settlement	142,790	454,190	496,940	560,840	626,990	596,840	700,340	761,540	772,790	757,490	722,990	619,640	7,213,380
6	Adjustment to Fuel Cost	0	(311,629)	(248,867)	0	(6,381)	105,679	0	0	0	0	0	0	(461,198)
7	**Total Fuel & Net Power Trans.**	$ 31,294,212	$ 20,792,810	$ 26,998,329	$ 28,346,581	$ 36,511,103	$ 38,894,737	$ 38,786,102	$ 38,132,513	$ 33,074,046	$ 30,162,621	$ 25,861,747	$ 27,430,005	$ 376,284,806
8	System kWh Sold	889,585,775	688,650,292	767,853,846	774,628,555	1,036,274,670	1,144,179,994	1,213,105,000	1,202,044,000	1,031,218,000	871,876,000	752,985,000	852,156,000	11,224,557,132
8a	Jurisdictional % of Total Sales	97.2125%	97.3404%	97.3528%	97.4205%	97.3524%	97.6021%	97.4627%	97.4765%	97.4132%	97.3683%	97.1456%	97.0517%	
9	Cost per kWh Sold (¢/kWh)	3.5178	3.0194	3.5161	3.6594	3.5233	3.3994	3.1973	3.1723	3.2073	3.4595	3.4346	3.2189	3.3523
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)	3.5220	3.0230	3.5203	3.6638	3.5275	3.4035	3.2011	3.1761	3.2111	3.4637	3.4387	3.2228	3.3563
10	GPIF (¢/kWh) *	(0.0025)	(0.0032)	(0.0029)	(0.0028)	(0.0021)	(0.0019)	(0.0018)	(0.0018)	(0.0021)	(0.0025)	(0.0029)	(0.0026)	(0.0024)
11	True-Up (¢/kWh) *	(0.2256)	(0.2910)	(0.2610)	(0.2585)	(0.1934)	(0.1747)	(0.1650)	(0.1665)	(0.1942)	(0.2298)	(0.2667)	(0.2359)	(0.2142)
12	TOTAL	3.2939	2.7288	3.2564	3.4025	3.3320	3.2269	3.0343	3.0078	3.0148	3.2314	3.1691	2.9843	3.1398
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	3.2963	2.7308	3.2587	3.4049	3.3344	3.2292	3.0365	3.0100	3.0170	3.2337	3.1714	2.9864	3.1421
15	Tax Savings Credit	(0.0781)	(0.1007)	(0.0903)	(0.0895)	(0.0669)	(0.0605)	(0.0571)	(0.0576)	(0.0672)	(0.0795)	(0.0923)	(0.0816)	(0.0741)
16	**Recovery Factor Rounded to the Nearest .001 ¢/kWh**	3.218	2.630	3.168	3.315	3.268	3.169	2.979	2.952	2.950	3.154	3.079	2.905	3.068

* ¢/kWh calculations based on jurisdictional kWh sales

[1] Includes portion of Gulf's 25% ownership of Scherer Unit 3

GULF POWER COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(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 Projection	August Projection	September Projection	October Projection	November Projection	December Projection	TOTAL
	FUEL COST - NET GEN. ($)													
1	LIGHTER OIL (B.L.)	135,828	16,388	192,046	229,142	96,752	181,594	89,014	89,782	90,399	90,872	50,530	46,059	1,308,406
2	COAL	10,611,130	1,810,103	10,454,743	8,576,042	15,195,828	12,953,234	18,458,969	18,221,585	16,067,829	13,682,436	7,685,025	8,967,455	142,684,379
2a	Coal at Scherer	2,137,289	(314)	(6,146)	1,518,970	2,748,393.26	2,135,307	3,206,335	3,104,304	2,638,536	2,218,199	1,743,780	2,520,809	23,965,463
2b	Scherer/Flint Credit	(511,810)	0	1,542	(376,161)	(655,820)	(513,523)	(763,108)	(738,824)	(627,972)	(527,931)	(415,020)	(599,953)	(5,728,579)
3	GAS - Generation	10,084,319	8,400,206	8,622,667	5,569,290	4,564,376	6,449,596	10,458,056	12,430,103	9,991,145	10,396,571	6,519,767	9,142,282	102,628,377
4	GAS (B.L.)	301,908	231,213	19,924	202,957	240,715	199,510	168,408	168,408	167,736	171,012	176,472	93,876	2,142,139
5	Landfill Gas	62,171	61,038	70,668	70,607	70,525	68,707	74,408	74,408	72,066	74,408	72,066	74,408	845,480
6	OIL - C.T.	24,471	10,170	8,650	35,297	0	199	56,956	0	0	0	0	0	135,743
7	TOTAL ($)	22,845,305	10,528,804	19,364,093	15,826,144	22,260,770	21,474,625	31,749,038	33,349,766	28,399,739	26,105,567	15,832,620	20,244,936	267,981,408
	SYSTEM NET GEN. (MWH)													
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL	324,217	70,363	310,648	219,005	408,796	361,738	593,978	589,116	516,075	436,423	235,877	279,973	4,346,209
9a	Coal at Scherer	71,578	(894)	(851)	50,673	93,850	70,063	113,925	111,001	95,512	79,784	62,178	91,993	838,812
9b	Scherer/Flint Credit	(17,080)	0	0	(12,206)	(22,394)	(16,765)	(27,114)	(26,418)	(22,732)	(18,989)	(14,798)	(21,894)	(200,390)
10	GAS	368,800	361,281	337,689	191,948	145,554	203,045	354,042	463,734	391,177	422,622	278,700	391,186	3,909,778
11	Landfill Gas	1,771	1,711	2,018	2,004	1,969	1,905	2,097	2,097	2,031	2,097	2,031	2,097	23,828
12	OIL - C.T.	28	24	19	132	(11)	24	256	0	0	0	0	0	472
13	TOTAL (MWH)	749,314	432,485	649,523	451,556	627,764	620,010	1,037,184	1,139,530	982,063	921,937	563,988	743,355	8,918,709
	UNITS OF FUEL BURNED													
14	LIGHTER OIL (BBL)	1,592	195	2,287	2,539	1,137	2,098	1,018	1,018	1,018	1,018	564	513	14,996
15	COAL excl. Scherer (TON) (2)	167,418	26,854	156,055	131,808	224,142	191,317	291,465	291,730	258,308	216,940	119,653	139,304	2,214,994
16	GAS-all (MCF) (1)	2,502,591	2,416,864	2,277,147	1,363,858	1,001,584	1,371,459	2,954,901	3,736,174	2,943,722	3,072,647	2,031,835	2,770,839	28,443,621
17	OIL - C.T. (BBL)	257	107	91	381	0	2	615	0	0	0	0	0	1,453
	BTU'S BURNED (MMBTU)													
18	COAL + GAS B.L. + OIL B.L.	4,180,599	601,900	3,359,497	3,045,205	5,256,477	4,688,622	7,241,479	7,182,880	6,348,822	5,408,381	3,177,888	3,794,848	54,286,597
19	GAS-Generation (1)	2,546,145	2,466,142	2,322,216	1,293,547	1,000,675	1,393,435	2,894,901	3,676,174	2,883,722	3,012,647	1,971,835	2,740,839	28,202,278
20	OIL - C.T.	1,498	622	529	2,214	0	12	3,601	0	0	0	0	0	8,476
21	TOTAL (MMBTU)	6,728,242	3,068,664	5,682,242	4,340,966	6,257,152	6,082,069	10,139,981	10,859,054	9,232,544	8,421,028	5,149,723	6,535,687	82,497,352

(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 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(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 Projection	August Projection	September Projection	October Projection	November Projection	December Projection	TOTAL
	GENERATION MIX (% MWH)													
22	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
23	COAL	50.54	16.05	47.69	57.02	76.50	66.94	65.65	59.12	59.96	53.93	50.22	47.09	55.88
24	GAS-Generation	49.22	83.54	52.00	42.51	23.19	32.75	34.13	40.70	39.83	45.84	49.42	52.62	43.84
25	Landfill Gas	0.24	0.40	0.31	0.44	0.31	0.31	0.20	0.18	0.21	0.23	0.36	0.29	0.27
26	OIL - C.T.	0.00	0.01	0.00	0.03	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.01
27	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													
28	LIGHTER OIL ($/BBL)	85.32	84.04	83.97	90.25	85.09	86.56	87.46	88.22	88.82	89.29	89.59	89.83	87.25
29	COAL ($/TON) (2)	63.38	67.41	66.99	65.06	67.80	67.71	63.33	62.46	62.20	63.07	64.23	64.37	64.42
30	GAS + B.L. ($/MCF) (1)	4.08	3.51	3.69	4.09	4.63	4.73	3.54	3.33	3.40	3.39	3.22	3.28	3.61
31	OIL - C.T.	95.22	95.05	95.05	92.64	0.00	99.50	92.60	0.00	0.00	0.00	0.00	0.00	93.42
	FUEL COST $ / MMBTU													
32	COAL + GAS B.L. + OIL B.L.	3.03	3.42	3.17	3.33	3.35	3.19	2.92	2.90	2.89	2.89	2.91	2.91	3.03
33	GAS-Generation (1)	3.89	3.35	3.61	4.16	4.39	4.51	3.56	3.34	3.41	3.40	3.23	3.28	3.57
34	OIL - C.T.	16.34	16.35	16.35	15.94	0.00	16.58	15.82	0.00	0.00	0.00	0.00	0.00	16.01
35	TOTAL ($/MMBTU)	3.36	3.36	3.35	3.59	3.52	3.49	3.11	3.05	3.05	3.07	3.03	3.06	3.21
	BTU BURNED BTU / KWH													
36	COAL + GAS B.L. + OIL B.L.	11,039	8,664	10,844	11,827	10,945	11,297	10,637	10,662	10,782	10,877	11,219	10,840	10,891
37	GAS-Generation (1)	7,026	6,935	7,064	6,992	7,174	7,060	8,311	8,026	7,478	7,226	7,218	7,110	7,352
38	OIL - C.T.	53,500	25,917	27,842	16,773	0	500	14,066	0	0	0	0	0	17,958
39	TOTAL (BTU/KWH)	9,078	7,218	8,899	9,808	10,097	9,931	9,851	9,595	9,474	9,212	9,255	8,885	9,352
	FUEL COST CENTS / KWH													
40	COAL + GAS B.L. + OIL B.L.	3.35	2.96	3.44	3.94	3.67	3.60	3.11	3.09	3.11	3.14	3.26	3.15	3.30
41	GAS-Generation	2.73	2.33	2.55	2.90	3.14	3.18	2.95	2.68	2.55	2.46	2.34	2.34	2.62
42	Landfill Gas	3.51	3.57	3.50	3.52	3.58	3.61	3.55	3.55	3.55	3.55	3.55	3.55	3.55
43	OIL - C.T.	87.40	42.38	45.53	26.74	0.00	0.83	22.25	0.00	0.00	0.00	0.00	0.00	28.76
44	TOTAL (¢/KWH)	3.05	2.43	2.98	3.50	3.55	3.46	3.06	2.93	2.89	2.83	2.81	2.72	3.00

(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 2019

(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	Crist 4	75	(539)	0.0%	0.0%	0.0%							
2	Coal						-	-	-	-	-	0	0
3	Gas-G							-	-	-	-	0	0
4	Gas-S							-	-	-	-		0
5	Oil-S							-	-	-	-		0
6	Crist 5	75	(533)	0.0%	0.0%	0.0%							
7	Coal						-	-	-	-	-	0	0
8	Gas-G							-	-	-	-	0	0
9	Gas-S							-	-	-	-		0
10	Oil-S							-	-	-	-		0
11	Crist 6	299		32.8%	100.0%	74.3%							
12	Coal		72,889				10,561	34,193	11,256	769,753	2,221,635	3.05	64.97
13	Gas-G		-					-	-	-	-	0	0
14	Gas-S							10,667	1,019	10,867	202,824		19.01
15	Oil-S							3	139,075	17	243		81.00
16	Crist 7	475		51.2%	82.8%	62.2%	10,437						
17	Coal		180,963					84,233	11,211	1,888,672	5,472,904	3.02	64.97
18	Gas-G		-					-	-	-	-	0	0
19	Gas-S							5,211	1,019	5,309	99,083		19.01
20	Oil-S							468	139,075	2,728	39,931		85.32
21	Smith 3	621	362,382	78.4%	100.0%	78.4%	7,026						
22	Gas-G							2,486,713	1,024	2,546,145	9,906,966	2.73	3.98
23	Smith A	40	28	0.1%	100.0%	47.5%	53,486						
24	Oil							257	138,500	1,498	24,471	87.40	95.22
25	Scherer 3[2]	216	71,578	44.5%	100.0%	44.5%	10,998						
26	Coal								38,696	787,180	2,055,379	2.87	0
27	Oil							88	138,500	511	7,605		86.42
28	Scherer/Flint Credit	(52)	(17,080)		N/A	N/A							
29	Coal								N/A	(187,835)	(490,450)	N/A	N/A
30	Oil							(21)	N/A	(122)	(1,815)	N/A	N/A
31	Other Generation		6,418										
32	Gas										177,353	2.76	0.00
33	Perdido		1,771										
34	Landfill Gas										62,171	3.51	0.00
35	Daniel 1[3]	251	22,302	11.9%	94.9%	33.1%	12,708						
36	Coal							15,392	9,206	283,410	916,296	4.11	59.53
37	Oil-S							439	138,500	2,554	36,678		83.55
38	Daniel 2[3]	251	49,136	26.3%	86.1%	30.4%	12,015						
39	Coal							33,600	8,785	590,342	2,000,295	4.07	59.53
40	Oil-S							615	138,500	3,577	51,371		83.53
41	Gas,BL												
42	Gas												
43	Ltr. Oil												
44	Oil												
45	Total	2,251	749,314	44.7%	89.9%	56.8%	9,047			6,704,606	22,782,940	3.04	

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
31,045	Scherer Inv Adjustment - Coal	81,909	
(7,408)	Scherer/Flint Credit Inv Adj. - Coal	(19,545)	
	Recoverable Fuel	**22,845,305**	**3.05**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: FEBRUARY 2019

(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	Crist 4	75	(699)	0.0%	100.0%	0.0%	N/A						
2	Coal							-	-	-	-	0.00	0
3	Gas-G							-	-	-	-	0	0
4	Gas-S							-	-	-	-		0
5	Oil-S							-	-	-	-		0
6	Crist 5	75	(700)	0.0%	100.0%	0.0%	N/A						
7	Coal							-	-	-	-	0.00	0
8	Gas-G							-	-	-	-	0	0
9	Gas-S							-	-	-	-		0
10	Oil-S							-	-	-	-		0
11	Crist 6	299		1.9%	100.0%	45.4%	-						
12	Coal		3,825					-	11,224	-	-	0.00	0
13	Gas-G							-	-	-	-	0	0
14	Gas-S							2,138	1,022	2,185	94,624		44.26
15	Oil-S							-	-	-	-		0
16	Crist 7	475		20.2%	100.0%	60.7%	8,363						
17	Coal		64,540					23,707	11,384	539,761	1,631,419	2.53	68.82
18	Gas-G							-	-	-	-	0	0
19	Gas-S							3,087	1,022	3,155	136,589		44.25
20	Oil-S							81	139,075	471	6,861		84.70
21	Smith 3	621	355,633	85.2%	100.0%	85.2%	6,935						
22	Gas-G							2,411,639	1,023	2,466,142	8,250,748	2.32	3.42
23	Smith A	40	24	0.1%	99.3%	60.0%	25,913						
24	Oil							107	138,388	622	10,170	42.38	95.05
25	Scherer 3[2]	216	(894)	0.0%	1.8%	0.0%	-						
26	Coal							-	-		(314)	0.04	0
27	Oil							-	-	-	-		0
28	Scherer/Flint Credit	0	-										
29	Coal								N/A	-	-	N/A	N/A
30	Oil							-	N/A	-	-	N/A	N/A
31	Other Generation		5,648										
32	Gas										149,458	2.65	0.00
33	Perdido		1,711										
34	Landfill Gas										61,038	3.57	0.00
35	Daniel 1[3]	251	2,732	1.6%	98.8%	12.0%	16,825						
36	Coal							2,574	8,929	45,966	152,723	5.59	59.33
37	Oil-S							73	8,929	28	6,113		83.74
38	Daniel 2[3]	251	665	0.4%	92.0%	6.2%	15,337						
39	Coal							573	8,900	10,199	34,004	5.11	59.34
40	Oil-S							41	8,929	15	3,414		83.27
41	Gas,BL												
42	Gas												
43	Ltr. Oil												
44	Oil											N/A	N/A
45	Total	2,303	432,484	27.9%	89.8%	44.4%	7,218			3,068,544	10,536,847	2.44	

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 Depr	(8,043)	
	Recoverable Fuel	**10,528,804**	**2.43**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: MARCH 2019

(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	Crist 4	75		4.5%	100.0%	48.1%	12,432						
2	Coal		-					-	-	-	-	0	0
3	Gas-G		2,499					30,616	1,025	31,067	187,436	7.50	6.12
4	Gas-S							1,961	1,025	2,010	12,126		6.18
5	Oil-S							1	139,075	7	101		101.00
6	Crist 5	75		5.8%	100.0%	49.0%	14,977						
7	Coal		-					-	-	-	-	0	0
8	Gas-G		3,258					47,613	1,025	48,795	294,387	9.04	6.18
9	Gas-S							1,089	1,025	1,116	6,734		6.18
10	Oil-S							40	139,075	231	3,370		84.25
11	Crist 6	299		12.3%	100.0%	62.2%	9,131						
12	Coal		26,566					10,946	11,081	242,585	756,512	2.85	69.11
13	Gas-G		690					6,150	1,025	6,302	38,022	5.51	6.18
14	Gas-S							172	1,025	176	1,064		6.19
15	Oil-S							12	139,075	73	1,062		88.50
16	Crist 7	475		62.1%	100.0%	62.2%	10,579						
17	Coal		219,428					102,515	11,322	2,321,350	7,085,130	3.23	69.11
18	Gas-G							-	-	-	-	0	0
19	Gas-S							-	-	-	-		0
20	Oil-S							108	139,075	631	9,193		85.12
21	Smith 3	604	322,298	71.7%	82.3%	71.8%	6,938						
22	Gas-G							2,189,846	1,021	2,236,052	7,864,861	2.44	3.59
23	Smith A	36	19	0.1%	98.0%	57.6%	27,842						
24	Oil							91	138,388	529	8,650	45.53	95.05
25	Scherer 3[2]	216	(851)	0.0%	0.0%	0.0%	-						
26	Coal								-	-	(6,146)	0.72	0
27	Oil							-	-	-	-		0
28	Scherer/Flint Credit	0	-		N/A	N/A							
29	Coal								N/A	-	1,542	N/A	N/A
30	Oil							-	N/A	-	-	N/A	N/A
31	Other Generation		8,944										
32	Gas										237,961	2.66	0.00
33	Perdido		2,018										
34	Landfill Gas										70,668	3.50	0.00
35	Daniel 1[3]	251	21,030	11.3%	93.4%	36.0%	12,485						
36	Coal							14,252	9,211	262,550	869,826	4.14	61.03
37	Oil-S							1,120	139,240	6,548	93,913		83.85
38	Daniel 2[3]	251	43,624	23.4%	81.8%	36.5%	11,836						
39	Coal							28,342	9,109	516,335	1,725,776	3.96	60.89
40	Oil-S							1,006	139,240	5,885	84,407		83.90
41	Gas,BL												
42	Gas												
43	Ltr. Oil												
44	Oil											N/A	N/A
45	Total	2,282	649,523	38.3%	83.1%	52.2%	8,899			5,682,242	19,346,594	2.98	

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 Depr	(4,022)	
	Crist Coal Additive	21,521	
	Recoverable Fuel	**19,364,093**	**2.98**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: APRIL 2019

(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	Crist 4	75	(997)	0.0%	100.0%	48.1%	N/A						
2	Coal							-	-	-	-	0	0
3	Gas-G							-	-	-	-	0	0
4	Gas-S							-	-	-	-		0
5	Oil-S							-	-	-	-		0
6	Crist 5	75	(1,003)	0.0%	100.0%	49.0%	N/A						
7	Coal							-	-	-	-	0	0
8	Gas-G							-	-	-	-	0	0
9	Gas-S							-	-	-	-		0
10	Oil-S							-	-	-	-		0
11	Crist 6	299	(2,824)	0.0%	100.0%	62.2%	N/A						
12	Coal							-	-	-	-	0	0
13	Gas-G							-	-	-	-	0	0
14	Gas-S							-	-	-	-		0
15	Oil-S							-	-	-	-		0
16	Crist 7	475		23.2%	56.1%	62.2%	10,732						
17	Coal		79,494					39,298	10,852	852,924	2,698,380	3.39	68.66
18	Gas-G		3					272	1,013	275	555	18.50	2.04
19	Gas-S							99,390	1,013	100,683	202,957		2.04
20	Oil-S							160	139,075	932	14,040		87.75
21	Smith 3	604	184,989	42.5%	50.0%	71.8%	6,991						
22	Gas-G							1,264,196	1,023	1,293,272	5,377,853	2.91	4.25
23	Smith A	36	132	0.5%	100.0%	57.6%	16,773						
24	Oil							381	138,338	2,214	35,298	26.74	92.65
25	Scherer 3[2]	216	50,673	32.6%	68.2%	47.6%	11,061						
26	Coal								142	560,500	1,518,970	3.00	0
27	Oil							425	138,388	2,471	42,649		100.35
28	Scherer/Flint Credit	(52)	(12,206)		N/A	N/A	N/A						
29	Coal								N/A	(135,014)	(365,888)	N/A	N/A
30	Oil							(102)	N/A	(595)	(10,273)	N/A	N/A
31	Other Generation		6,956										
32	Gas										190,882	2.74	0.00
33	Perdido		2,004										
34	Landfill Gas										70,607	3.52	0.00
35	Daniel 1[3]	251	71,663	39.7%	94.8%	39.7%	11,341						
36	Coal							46,080	8,819	812,759	2,917,536	4.07	63.31
37	Oil-S							348	139,147	2,035	29,193		83.89
38	Daniel 2[3]	251	72,673	40.2%	92.3%	10.3%	11,538						
39	Coal							46,430	9,030	838,526	2,939,697	4.05	63.31
40	Oil-S							1,708	139,147	9,984	143,259		83.88
41	Gas,BL												
42	Gas												
43	Ltr. Oil												
44	Oil											N/A	N/A
45	Total	2,230	451,557	28.1%	74.9%	55.5%	9,808			4,340,965	15,805,714	3.50	

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 Depr	(4,022)	
	Crist Coal Additive	24,451	
	Recoverable Fuel	**15,826,144**	**3.50**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: MAY 2019

(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	Crist 4	75	(447)	0.0%	100.0%	0.0%	N/A						
2	Coal							-	-	-	-	0	0
3	Gas-G							-	-	-	-	0	0
4	Gas-S							-	-	-	-		0
5	Oil-S							-	-	-	-		0
6	Crist 5	75	(443)	0.0%	100.0%	0.0%	N/A						
7	Coal							-	-	-	-	0	0
8	Gas-G							-	-	-	-	0	0
9	Gas-S							-	-	-	-		0
10	Oil-S							-	-	-	-		0
11	Crist 6	299		32.4%	99.7%	65.3%	11,756						
12	Coal		71,993					37,933	11,156	846,361	2,676,470	3.72	70.56
13	Gas-G							-	-	-	-	0	0
14	Gas-S							12,863	11,156	13,068	132,466		10.30
15	Oil-S							6	139,075	33	497		82.83
16	Crist 7	475		62.6%	100.0%	62.6%	10,610						
17	Coal		220,762					103,922	11,269	2,342,194	7,332,510	3.32	70.56
18	Gas-G		461					4,822	1,016	4,899	49,655	10.77	10.30
19	Gas-S							10,511	1,016	10,680	108,249		10.30
20	Oil-S							72	139,075	421	6,348		88.17
21	Smith 3	604	139,031	30.9%	39.5%	42.3%	7,162						
22	Gas-G							973,388	1,023	995,776	4,343,015	3.12	4.46
23	Smith A	36	(11)	0.0%	100.0%	0.0%	-						
24	Oil							-	-	-	-	0.00	N/A
25	Scherer 3[2]	216	93,850	58.4%	100.0%	58.7%	10,772						
26	Coal							-	8,298	1,010,936	2,748,393	2.93	0
27	Oil							-	138,388	-	3		0
28	Scherer/Flint Credit	(52)	(22,394)		N/A	N/A							
29	Coal								N/A	(241,229)	(655,819)	N/A	N/A
30	Oil							-	N/A	-	(1)	N/A	N/A
31	Other Generation		6,063										
32	Gas										171,706	2.83	0.00
33	Perdido		1,969										
34	Landfill Gas										70,525	3.58	0.00
35	Daniel 1[3]	251	65,517	35.1%	98.8%	43.8%	11,136						
36	Coal							39,808	9,164	729,601	2,498,461	3.81	62.76
37	Oil-S							392	138,807	2,284	33,248		84.82
38	Daniel 2[3]	251	51,415	27.5%	94.4%	47.7%	10,469						
39	Coal							24,080	11,176	538,236	1,511,340	2.94	62.76
40	Oil-S							667	138,807	3,891	56,657		84.94
41	Gas,BL												
42	Gas												
43	Ltr. Oil												
44	Oil											N/A	N/A
45	Total	2,230	627,764	37.8%	85.1%	49.5%	10,097			6,257,151	21,083,723	3.36	

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 Depr	(4,022)	
	Crist Coal Additive	10,785	
18,399	Inventory Adjustment -Coal	1,170,284	
	Recoverable Fuel	**22,260,771**	**3.55**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUALS FOR THE MONTH OF: JUNE 2019

(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	Crist 4	75	(452)	0.0%	100.0%	0.0%	N/A						
2	Coal							-	-	-	-	0	0
3	Gas-G							-	-	-	-	0	0
4	Gas-S							-	-	-	-		0
5	Oil-S							-	-	-	-		0
6	Crist 5	75	(454)	0.0%	100.0%	0.0%	N/A						
7	Coal							-	-	-	-	0	0
8	Gas-G							-	-	-	-	0	0
9	Gas-S							-	-	-	-		0
10	Oil-S							-	-	-	-		0
11	Crist 6	299		30.5%	99.9%	60.7%	11,699						
12	Coal		65,563					33,823	11,339	767,038	2,398,254	3.66	70.91
13	Gas-G		3					36	1,016	37	632	21.07	17.56
14	Gas-S							4,852	1,016	4,942	84,424		17.40
15	Oil-S							32	139,075	181	2,726		85.19
16	Crist 7	475		54.2%	92.8%	58.3%	10,953						
17	Coal		184,598					90,302	11,195	2,021,862	6,402,953	3.47	70.91
18	Gas-G		603					6,482	1,016	6,602	112,782	18.70	17.40
19	Gas-S							2,461	1,016	2,507	42,827		17.40
20	Oil-S							734	139,075	4,291	64,625		88.04
21	Smith 3	604	196,762	46.0%	48.7%	71.7%	7,070						
22	Gas-G							1,357,628	1,025	1,391,026	6,249,986	3.18	4.60
23	Smith A	36	24	0.1%	100.0%	64.3%	500						
24	Oil							2	138,388	12	199	0.83	99.50
25	Scherer 3[2]	216	70,063	45.1%	92.7%	47.7%	11,187						
26	Coal								8,341	783,780	2,135,307	3.05	0
27	Oil							128	138,500	747	10,754		84.02
28	Scherer/Flint Credit	(52)	(16,765)		N/A	N/A							
29	Coal								N/A	(187,548)	(510,949)	N/A	N/A
30	Oil							(31)	N/A	(179)	(2,573)	N/A	N/A
31	Other Generation		5,677										
32	Gas										158,455	2.79	0.00
33	Perdido		1,905										
34	Landfill Gas										68,707	3.61	0.00
35	Daniel 1[3]	251	50,373	27.9%	99.4%	40.2%	11,413						
36	Coal							31,518	9,120	574,888	1,949,477	3.87	61.85
37	Oil-S							330	138,393	1,919	27,668		83.84
38	Daniel 2[3]	251	62,110	34.4%	81.8%	37.7%	11,346						
39	Coal							35,674	9,877	704,704	2,206,572	3.55	61.85
40	Oil-S							905	138,393	5,260	75,821		83.78
41	Gas,BL												
42	Gas												
43	Ltr. Oil												
44	Oil											N/A	N/A
45	Total	2,230	620,009	38.6%	84.1%	54.4%	9,931			6,082,069	21,478,647	3.46	

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 Depr	(4,022)	
	Recoverable Fuel	**21,474,624**	**3.46**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: JULY 2019

(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	Crist 4	75		39.6%	96.0%	64.8%	12,640						
2	Coal		-					-	-	-	-	0	N/A
3	Gas-G		22,123					274,145	1,020	279,628	931,452	4.21	3.40
4	Gas-S							-	-	-	-		N/A
5	Oil-S							-	-	-	-		N/A
6	Crist 5	75		67.8%	96.0%	64.8%	12,089						
7	Coal		-					-	-	-	-	0	N/A
8	Gas-G		37,816					448,185	1,020	457,148	1,429,715	3.78	3.19
9	Gas-S							-	-	-	-		N/A
10	Oil-S							-	-	-	-		N/A
11	Crist 6	299		54.9%	96.5%	56.9%	11,023						
12	Coal		122,091					59,097	11,386	1,345,798	3,916,739	3.21	66.28
13	Gas-G		-					-	-	-	-	0	N/A
14	Gas-S							-	-	-	-		N/A
15	Oil-S							-	-	-	-		N/A
16	Crist 7	475		74.6%	95.6%	78.1%	10,439						
17	Coal		263,718					120,883	11,386	2,752,840	8,011,721	3.04	66.28
18	Gas-G		-					-	-	-	-	0	N/A
19	Gas-S							-	-	-	-		N/A
20	Oil-S							-	-	-	-		N/A
21	Smith 3	594	288,391	65.3%	98.0%	66.6%	7,483						
22	Gas-G							2,115,809	1,020	2,158,125	7,940,685	2.75	3.75
23	Smith A	32	256	1.1%	98.4%	0.1%	14,066						
24	Oil							615	139,400	3,601	56,956	22.25	92.60
25	Scherer 3[2]	216	113,925	71.0%	95.7%	57.1%	10,582						
26	Coal								8,399	1,205,555	3,206,335	2.81	N/A
27	Oil							-	-	-	-		
28	Scherer/Flint Credit	(13)	(27,114)		N/A	N/A							
29	Coal								N/A	(286,922)	(763,108)	N/A	N/A
30	Oil								N/A				
31	Other Generation		5,712										
32	Gas										156,204		
33	Perdido		2,097										
34	Landfill Gas										74,408		
35	Daniel 1[3]	251	97,239	52.1%	95.7%	56.9%	10,444						
36	Coal							52,458	9,680	1,015,541	3,072,862	3.16	58.58
37	Oil-S							-	-	-	-		
38	Daniel 2[3]	251	110,930	59.4%	95.7%	62.1%	10,301						
39	Coal							59,027	9,680	1,142,708	3,457,647	3.12	58.58
40	Oil-S							-	-	-	-		
41	Gas,BL												
42	Gas							58,824	1,020	60,000	168,408	N/A	2.86
43	Ltr. Oil												
44	Oil							1,018	139,400	5,959	89,014	N/A	87.44
45	Total	2,255	1,037,184	61.8%	97.0%	64.6%	9,851			10,139,981	31,749,038	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
	Recoverable Fuel	**31,749,038**	**3.06**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: AUGUST 2019

(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	Crist 4	75		58.4%	96.0%	63.4%	12,685						
2	Coal		-					-	-	-	-	0	N/A
3	Gas-G		32,563					404,973	1,020	413,072	1,306,002	4.01	3.22
4	Gas-S							-	-	-	-		N/A
5	Oil-S							-	-	-	-		N/A
6	Crist 5	75		44.0%	96.0%	63.4%	12,083						
7	Coal		-					-	-	-	-	0	N/A
8	Gas-G		24,553					290,859	1,020	296,677	979,303	3.99	3.37
9	Gas-S							-	-	-	-		N/A
10	Oil-S							-	-	-	-		N/A
11	Crist 6	299		55.0%	96.5%	57.0%	11,021						
12	Coal		122,320					59,130	11,399	1,348,044	3,926,172	3.21	66.40
13	Gas-G		-					-	-	-	-	0	N/A
14	Gas-S							-	-	-	-		N/A
15	Oil-S							-	-	-	-		N/A
16	Crist 7	475		74.3%	95.6%	77.7%	10,444						
17	Coal		262,480					120,244	11,399	2,741,329	7,984,106	3.04	66.40
18	Gas-G							-	-	-	-	0	N/A
19	Gas-S							-	-	-	-		N/A
20	Oil-S							-	-	-	-		N/A
21	Smith 3	594	400,906	90.8%	98.0%	93.4%	7,399						
22	Gas-G							2,908,260	1,020	2,966,425	9,988,594	2.49	3.43
23	Smith A	32	-	0.0%	97.7%	0.0%	N/A						
24	Oil							-	-	-	-	N/A	N/A
25	Scherer 3[2]	216	111,001	69.2%	95.7%	56.2%	10,630						
26	Coal								8,398	1,179,891	3,104,304	2.80	N/A
27	Oil							-	-	-	-		
28	Scherer/Flint Credit	(51)	(26,418)		N/A	N/A							
29	Coal								N/A	(280,814)	(738,825)	N/A	N/A
30	Oil								N/A				
31	Other Generation		5,712										
32	Gas										156,204		
33	Perdido		2,097										
34	Landfill Gas										74,408		
35	Daniel 1[3]	251	97,922	52.4%	95.7%	54.8%	10,508						
36	Coal							54,317	9,472	1,028,978	3,051,108	3.12	56.17
37	Oil-S							-	-	-	-		
38	Daniel 2[3]	251	106,394	57.0%	95.7%	60.9%	10,334						
39	Coal							58,039	9,472	1,099,493	3,260,199	3.06	56.17
40	Oil-S							-	-	-	-		
41	Gas,BL												
42	Gas							58,824	1,020	60,000	168,408	N/A	2.86
43	Ltr. Oil												
44	Oil							1,018	139,400	5,959	89,782	N/A	88.19
45	Total	2,216	1,139,530	69.1%	98.7%	72.2%	9,529			10,859,054	33,349,765	2.93	

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
	Recoverable Fuel	**33,349,765**	**2.93**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: SEPTEMBER 2019

(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	Crist 4	75		14.7%	96.0%	62.9%	12,703						
2	Coal		-					-	-	-	-	0	N/A
3	Gas-G		7,929					98,748	1,020	100,723	423,444	5.34	4.29
4	Gas-S							-	-	-	-		N/A
5	Oil-S							-	-	-	-		N/A
6	Crist 5	75		0.0%	96.0%	62.9%	N/A						
7	Coal		-					-	-	-	-	0	N/A
8	Gas-G		-					-	-	-	-	0	N/A
9	Gas-S							-	-	-	-		N/A
10	Oil-S							-	-	-	-		N/A
11	Crist 6	299		54.3%	96.5%	56.2%	11,038						
12	Coal		116,877					56,560	11,405	1,290,136	3,758,841	3.22	66.46
13	Gas-G		-					-	-	-	-	0	N/A
14	Gas-S							-	-	-	-		N/A
15	Oil-S							-	-	-	-		N/A
16	Crist 7	475		69.9%	95.6%	73.2%	10,510						
17	Coal		239,100					110,170	11,405	2,512,993	7,321,661	3.06	66.46
18	Gas-G		-					-	-	-	-	0	N/A
19	Gas-S							-	-	-	-		N/A
20	Oil-S							-	-	-	-		N/A
21	Smith 3	594	377,720	88.4%	98.1%	93.0%	7,368						
22	Gas-G							2,728,430	1,020	2,782,999	9,416,528	2.49	3.45
23	Smith A	32	-	0.0%	98.5%	0.0%	N/A						
24	Oil							-	-	-	-	N/A	N/A
25	Scherer 3[2]	216	95,512	61.5%	95.7%	49.4%	10,607						
26	Coal								8,405	1,013,077	2,638,536	2.76	N/A
27	Oil							-	-	-	-		
28	Scherer/Flint Credit	(51)	(22,732)		N/A	N/A							
29	Coal								N/A	(241,112)	(627,972)	N/A	N/A
30	Oil								N/A				
31	Other Generation		5,528										
32	Gas										151,173		
33	Perdido		2,031										
34	Landfill Gas										72,066		
35	Daniel 1[3]	251	81,136	44.9%	95.7%	46.9%	10,793						
36	Coal							46,958	9,324	875,688	2,557,336	3.15	54.46
37	Oil-S							-	-	-	-		
38	Daniel 2[3]	251	78,963	43.7%	95.7%	54.1%	10,538						
39	Coal							44,620	9,324	832,081	2,429,990	3.08	54.46
40	Oil-S							-	-	-	-		
41	Gas,BL												
42	Gas							58,824	1,020	60,000	167,736	N/A	2.85
43	Ltr. Oil												
44	Oil							1,018	139,400	5,959	90,399	N/A	88.80
45	Total	2,216	982,064	61.5%	98.7%	68.7%	9,401			9,232,544	28,399,738	2.89	

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
	Recoverable Fuel	**28,399,738**	**2.89**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: OCTOBER 2019

(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	Crist 4	75		0.0%	93.5%	0.0%	N/A						
2	Coal		-					-	-	-	-	0	N/A
3	Gas-G		-					-	-	-	-	0	N/A
4	Gas-S							-	-	-	-		N/A
5	Oil-S							-	-	-	-		N/A
6	Crist 5	75		0.0%	93.5%	0.0%	N/A						
7	Coal		-					-	-	-	-	0	N/A
8	Gas-G		-					-	-	-	-	0	N/A
9	Gas-S							-	-	-	-		N/A
10	Oil-S							-	-	-	-		N/A
11	Crist 6	299		50.3%	94.5%	56.2%	11,040						
12	Coal		111,893					54,142	11,408	1,235,271	3,605,661	3.22	66.60
13	Gas-G		-					-	-	-	-	0	N/A
14	Gas-S							-	-	-	-		N/A
15	Oil-S							-	-	-	-		N/A
16	Crist 7	475		62.4%	99.9%	70.2%	10,551						
17	Coal		220,546					101,987	11,408	2,326,872	6,791,958	3.08	66.60
18	Gas-G		-					-	-	-	-	0	N/A
19	Gas-S							-	-	-	-		N/A
20	Oil-S							-	-	-	-		N/A
21	Smith 3	638	416,910	87.8%	97.0%	92.0%	7,226						
22	Gas-G							2,953,575	1,020	3,012,647	10,240,367	2.46	3.47
23	Smith A	36	-	0.0%	98.4%	0.0%	N/A						
24	Oil							-	-	-	-	N/A	N/A
25	Scherer 3[2]	216	79,784	49.7%	93.5%	42.7%	10,727						
26	Coal								8,411	855,871	2,218,199	2.78	N/A
27	Oil							-	-	-	-		
28	Scherer/Flint Credit	(51)	(18,989)		N/A	N/A							
29	Coal								N/A	(203,697)	(527,931)	N/A	N/A
30	Oil								N/A				
31	Other Generation		5,712										
32	Gas										156,204		
33	Perdido		2,097										
34	Landfill Gas										74,408		
35	Daniel 1[3]	251	70,415	37.7%	93.5%	42.0%	11,038						
36	Coal							41,899	9,276	777,272	2,263,260	3.21	54.02
37	Oil-S							-	-	-	-		
38	Daniel 2[3]	251	33,569	18.0%	39.2%	55.3%	10,451						
39	Coal							18,912	9,276	350,833	1,021,557	3.04	54.02
40	Oil-S							-	-	-	-		
41	Gas,BL												
42	Gas							58,824	1,020	60,000	171,012	N/A	2.91
43	Ltr. Oil												
44	Oil							1,018	139,400	5,959	90,872	N/A	89.27
45	Total	2,264	921,937	54.7%	92.1%	62.9%	9,134			8,421,028	26,105,567	2.83	

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
	Recoverable Fuel	**26,105,567**	**2.83**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: NOVEMBER 2019

(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	Crist 4	75		0.0%	93.5%	0.0%	N/A						
2	Coal		-					-	-	-	-	0	N/A
3	Gas-G		-					-	-	-	-	0	N/A
4	Gas-S							-	-	-	-		N/A
5	Oil-S							-	-	-	-		N/A
6	Crist 5	75		0.0%	93.5%	0.0%	N/A						
7	Coal		-					-	-	-	-	0	N/A
8	Gas-G		-					-	-	-	-	0	N/A
9	Gas-S							-	-	-	-		N/A
10	Oil-S							-	-	-	-		N/A
11	Crist 6	299		4.2%	98.2%	56.2%	11,040						
12	Coal		9,072					4,390	11,409	100,157	296,043	3.26	67.44
13	Gas-G		-					-	-	-	-	0	N/A
14	Gas-S							-	-	-	-		N/A
15	Oil-S							-	-	-	-		N/A
16	Crist 7	475		51.4%	100.0%	56.2%	10,855						
17	Coal		175,777					83,624	11,409	1,908,068	5,639,839	3.21	67.44
18	Gas-G		-					-	-	-	-	0	N/A
19	Gas-S							-	-	-	-		N/A
20	Oil-S							-	-	-	-		N/A
21	Smith 3	638	273,172	59.5%	67.9%	90.7%	7,218						
22	Gas-G							1,933,171	1,020	1,971,835	6,368,594	2.33	3.29
23	Smith A	36	-	0.0%	97.9%	0.0%	N/A						
24	Oil							-	-	-	-	N/A	N/A
25	Scherer 3[2]	216	62,178	40.0%	93.5%	34.5%	10,870						
26	Coal								8,413	675,846	1,743,780	2.80	N/A
27	Oil							-	-	-	-		
28	Scherer/Flint Credit	(51)	(14,798)		N/A	N/A							
29	Coal								N/A	(160,851)	(415,020)	N/A	N/A
30	Oil								N/A				
31	Other Generation		5,528										
32	Gas										151,173		
33	Perdido		2,031										
34	Landfill Gas										72,066		
35	Daniel 1[3]	251	51,028	28.2%	93.5%	35.1%	11,589						
36	Coal							31,639	9,346	591,366	1,749,143	3.43	55.28
37	Oil-S							-	-	-	-		
38	Daniel 2[3]	251	-	0.0%	0.0%	0.0%	N/A						
39	Coal							-	-	-	-	N/A	N/A
40	Oil-S							-	-	-	-		
41	Gas,BL												
42	Gas							58,824	1,020	60,000	176,472	N/A	3.00
43	Ltr. Oil												
44	Oil							564	139,400	3,302	50,530	N/A	89.59
45	Total	2,264	563,988	34.6%	80.1%	51.9%	9,131			5,149,723	15,832,620	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
	Recoverable Fuel	**15,832,620**	**2.81**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: DECEMBER 2019

(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	Crist 4	75		0.0%	93.5%	0.0%	N/A						
2	Coal		-					-	-	-	-	0	N/A
3	Gas-G		-					-	-	-	-	0	N/A
4	Gas-S							-	-	-	-		N/A
5	Oil-S							-	-	-	-		N/A
6	Crist 5	75		0.0%	93.5%	0.0%	N/A						
7	Coal		-					-	-	-	-	0	N/A
8	Gas-G		-					-	-	-	-	0	N/A
9	Gas-S							-	-	-	-		N/A
10	Oil-S							-	-	-	-		N/A
11	Crist 6	299		0.0%	0.0%	0.0%	N/A						
12	Coal		-					-	-	-	-	0	N/A
13	Gas-G		-					-	-	-	-	0	N/A
14	Gas-S							-	-	-	-		N/A
15	Oil-S							-	-	-	-		N/A
16	Crist 7	475		59.9%	94.0%	63.8%	10,671						
17	Coal		211,714					99,007	11,409	2,259,182	6,709,164	3.17	67.76
18	Gas-G		-					-	-	-	-	0	N/A
19	Gas-S							-	-	-	-		N/A
20	Oil-S							-	-	-	-		N/A
21	Smith 3	655	385,474	79.1%	97.0%	88.1%	7,110						
22	Gas-G							2,687,097	1,020	2,740,839	8,986,078	2.33	3.34
23	Smith A	40	-	0.0%	97.8%	0.0%	N/A						
24	Oil							-	-	-	-	N/A	N/A
25	Scherer 3[2]	216	91,993	57.3%	93.5%	48.0%	10,643						
26	Coal								8,414	979,127	2,520,809	2.74	N/A
27	Oil							-	-	-	-		
28	Scherer/Flint Credit	(51)	(21,894)		N/A	N/A							
29	Coal								N/A	(233,032)	(599,953)	N/A	N/A
30	Oil								N/A				
31	Other Generation		5,712										
32	Gas										156,204		
33	Perdido		2,097										
34	Landfill Gas										74,408		
35	Daniel 1[3]	251	68,259	36.6%	93.5%	41.6%	11,084						
36	Coal							40,297	9,387	756,569	2,258,291	3.31	56.04
37	Oil-S							-	-	-	-		
38	Daniel 2[3]	251	-	0.0%	45.3%	0.0%	N/A						
39	Coal							-	-	-	-	N/A	N/A
40	Oil-S							-	-	-	-		
41	Gas,BL												
42	Gas							29,412	1,020	30,000	93,876	N/A	3.19
43	Ltr. Oil												
44	Oil							513	139,400	3,002	46,059	N/A	89.78
45	Total	2,286	743,354	43.7%	79.3%	47.6%	8,792			6,535,687	20,244,936	2.72	

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
	Recoverable Fuel	**20,244,936**	**2.72**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(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	Crist 4	75		9.4%	89.0%	0.2%	13,303						
2	Coal		-					-	-	-	-	N/A	N/A
3	Gas-G		61,980					808,482	1,020	824,490	2,848,334	4.60	3.52
4	Gas-S							1,961	1,025	2,010	12,126		6.18
5	Oil-S							1	166,667	7	101		101.00
6	Crist 5	75		9.5%	89.0%	24.1%	12,843						
7	Coal		-					-	-	-	-	N/A	N/A
8	Gas-G		62,494					786,657	1,020	802,620	2,703,405	4.33	3.44
9	Gas-S							1,089	1,025	1,116	6,734		6.18
10	Oil-S							40	137,500	231	3,370		84.25
11	Crist 6	299		27.5%	90.2%	54.4%	11,029						
12	Coal		720,265					350,214	11,343	7,945,143	23,556,327	3.27	67.26
13	Gas-G		693					6,186	1,025	6,339	38,654	5.58	6.25
14	Gas-S							30,692	1,018	31,238	515,402		16.79
15	Oil-S							53	136,568	304	4,528		85.43
16	Crist 7	475		55.9%	92.7%	65.6%	10,533						
17	Coal		2,323,120					1,079,892	11,329	24,468,047	73,081,745	3.15	67.68
18	Gas-G		1,067					11,576	1,017	11,776	162,992	15.28	14.08
19	Gas-S							120,660	1,014	122,334	589,705		4.89
20	Oil-S							1,623	138,984	9,474	140,998		86.87
21	Smith 3	614	3,703,668	68.9%	81.4%	78.8%	7,172						
22	Gas-G							26,009,752	1,021	26,561,283	94,934,275	2.56	3.65
23	Smith A	36	472	0.1%	98.8%	23.9%	17,958						
24	Oil-G							1,453	138,892	8,476	135,743	28.76	93.42
25	Scherer 3[(2)]	216	838,812	44.3%	77.5%	40.5%	10,791						
26	Coal									9,051,763	23,883,552	2.85	N/A
27	Oil							641		3,729	61,011		
28	Scherer/Flint Credit	(40)	(200,390)										
29	Coal							N/A	N/A	(2,158,055)	(5,694,372)	N/A	N/A
30	Oil							(154)	N/A	(896)	(14,662)		
31	Other Generation		73,610										
32	Gas									-	2,012,977		
33	Perdido		23,828										
34	Landfill Gas									-	845,480		
35	Daniel 1[(3)]	251	699,616	31.8%	95.6%	40.2%	11,084						
36	Coal							417,192	9,294	7,754,588	24,256,319	3.47	58.14
37	Oil-S							2,702	135,420	15,368	226,813		
38	Daniel 2[(3)]	251	609,479	27.7%	75.0%	33.4%	10,867						
39	Coal							349,297	9,481	6,623,457	20,587,077	3.38	58.94
40	Oil-S							4,942	137,847	28,612	414,929		
41	Gas,BL									-	-		
42	Gas							323,532	1,020	330,000	945,912	N/A	2.92
43	Ltr. Oil												
44	Oil							5,149	139,371	30,140	456,656	N/A	88.69
45	Total	2,252	8,918,709	4520.9%	87.7%	55.8%	9,349	30,313,632		82,473,594	266,716,131	2.99	

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
	Daniel Railcar Track Depr	(24,129)	
31,045	Scherer Inv Adjustment - Coal	81,909	
(7,408)	Scherer/Flint Credit Inv Adj. - Coal	(19,545)	
	Crist Coal Additive	56,757	
18,399	Inventory Adjustment - Coal	1,170,284	
	Recoverable Fuel	**267,981,408**	**3.00**

Total may not add due to rounding

GULF POWER COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(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)	2,825	324	1,744	4,167	1,099	1,503	950	951	1,021	1,013	567	516	16,680
3	UNIT COST ($/BBL)	73.01	72.93	91.76	89.61	80.21	76.99	91.02	91.03	91.33	91.29	91.70	91.70	85.45
4	AMOUNT ($)	206,246	23,630	160,025	373,414	88,147	115,712	86,467	86,574	93,247	92,476	51,992	47,315	1,425,245
5	*BURNED :*													
6	UNITS (BBL)	1,613	195	2,287	2,685	1,192	2,190	1,018	1,018	1,018	1,018	564	513	15,310
7	UNIT COST ($/BBL)	84.25	84.04	83.97	86.97	85.41	85.26	87.46	88.22	88.82	89.29	89.59	89.83	86.42
8	AMOUNT ($)	135,892	16,388	192,046	233,517	101,805	186,717	89,014	89,782	90,399	90,872	50,530	46,059	1,323,021
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	6,700	6,829	6,285	7,768	7,674	6,987	6,919	6,853	6,856	6,851	6,854	6,857	
11	UNIT COST ($/BBL)	84.81	84.27	86.47	87.97	87.27	85.69	86.16	86.53	86.90	87.20	87.37	87.51	
12	AMOUNT ($)	568,243	575,486	543,465	683,362	669,705	598,700	596,153	592,945	595,793	597,397	598,859	600,115	
	COAL EXCLUDING PLANT SCHERER													
13	*PURCHASES :*													
14	UNITS (TONS)	206,797	123,476	163,015	85,427	222,558	165,458	270,000	264,000	264,000	222,000	179,000	187,000	2,352,731
15	UNIT COST ($/TON)	64.94	65.54	64.27	72.41	64.55	66.97	61.89	61.13	61.13	62.83	64.32	64.27	63.80
16	AMOUNT ($)	13,429,192	8,092,634	10,476,793	6,185,485	14,365,204	11,079,932	16,709,762	16,137,092	16,137,092	13,948,568	11,513,930	12,018,666	150,094,350
17	*BURNED :*													
18	UNITS (TONS)	167,418	26,854	156,055	131,808	224,142	191,317	291,465	291,730	258,308	216,940	119,653	139,304	2,214,994
19	UNIT COST ($/TON)	60.73	63.35	62.58	63.45	64.16	65.21	63.33	62.46	62.20	63.07	64.23	64.37	63.18
20	AMOUNT ($)	10,166,593	1,701,138	9,766,531	8,362,747	14,380,558	12,476,685	18,458,969	18,221,585	16,067,829	13,682,436	7,685,025	8,967,455	139,937,551
21	*ENDING INVENTORY :*													
22	UNITS (TONS)	420,853	517,475	524,435	478,054	476,470	450,611	429,146	401,416	407,108	412,168	471,515	519,211	
23	UNIT COST ($/TON)	60.46	61.53	62.06	63.53	63.71	64.27	63.40	62.59	61.89	61.77	62.12	62.29	
24	AMOUNT ($)	25,446,771	31,838,267	32,548,528	30,371,267	30,355,914	28,959,161	27,209,954	25,125,461	25,194,724	25,460,856	29,289,761	32,340,972	

GULF POWER COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(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
	COAL at Plant Scherer [1]													
1	*PURCHASES :*													
2	UNITS (MMBTU)	1,013,526	523,373	330,078	610,716	450,913	345,670	664,871	883,432	1,149,106	1,286,106	1,283,519	1,264,670	9,805,980
3	UNIT COST ($/MMBTU)	2.56	3.03	2.98	2.64	2.78	2.77	2.56	2.59	2.58	2.58	2.56	2.56	2.63
4	AMOUNT ($)	2,593,108	1,587,217	984,969	1,610,743	1,251,573	956,001	1,701,030	2,287,629	2,966,110	3,317,742	3,291,465	3,242,610	25,790,197
5	*BURNED :*													
6	UNITS (MMBTU)	818,225	120	0	560,500	1,010,936	783,780	1,205,555	1,179,891	1,013,077	855,871	675,846	979,127	9,082,928
7	UNIT COST ($/MMBTU)	2.61	2.63	0.00	2.71	2.72	2.72	2.66	2.63	2.60	2.59	2.58	2.57	2.64
8	AMOUNT ($)	2,137,289	315	0	1,518,970	2,748,393	2,135,307	3,206,335	3,104,304	2,638,536	2,218,199	1,743,780	2,520,809	23,972,237
9	*ENDING INVENTORY :*													
10	UNITS (MMBTU)	2,158,676	2,682,169	3,012,247	3,062,463	2,502,440	2,064,330	1,523,646	1,227,187	1,363,216	1,793,451	2,401,124	2,686,667	
11	UNIT COST ($/MMBTU)	2.61	2.69	2.73	2.71	2.72	2.72	2.70	2.69	2.66	2.64	2.61	2.60	
12	AMOUNT ($)	5,635,927	7,223,459	8,208,427	8,300,200	6,803,380	5,624,073	4,118,768	3,302,093	3,629,667	4,729,210	6,276,895	6,998,696	
	GAS (Reported on a MMBTU and $ basis)													
13	*BURNED :*													
14	UNITS (MMBTU)	2,562,321	2,473,080	2,325,498	1,304,784	1,024,423	1,405,113	2,954,901	3,736,174	2,943,722	3,072,647	2,031,835	2,770,839	28,605,337
15	UNIT COST ($/MMBTU)	3.98	3.43	3.61	4.28	4.52	4.62	3.54	3.33	3.40	3.39	3.22	3.28	3.59
16	AMOUNT ($)	10,208,874	8,481,961	8,404,629	5,581,366	4,633,385	6,490,651	10,470,260	12,442,307	10,007,708	10,411,379	6,545,066	9,079,954	102,757,540
	OTHER - C.T. OIL													
17	*PURCHASES :*													
18	UNITS (BBL)	0	0	0	0	0	0	0	0	0	0	0	0	0
19	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	AMOUNT ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
21	*BURNED :*													
22	UNITS (BBL)	257	107	91	381	0	2	615	0	0	0	0	0	1,453
23	UNIT COST ($/BBL)	95.22	95.05	95.05	92.64	0.00	99.50	92.60	0.00	0.00	0.00	0.00	0.00	93.42
24	AMOUNT ($)	24,471	10,170	8,650	35,297	0	199	56,956	0	0	0	0	0	135,743
25	*ENDING INVENTORY :*													
26	UNITS (BBL)	7,388	7,281	7,190	6,993	6,993	6,991	6,376	6,376	6,376	6,376	6,376	6,376	
27	UNIT COST ($/BBL)	95.05	95.05	95.05	92.68	92.68	92.68	92.69	92.69	92.69	92.69	92.69	92.69	
28	AMOUNT ($)	702,252	692,082	683,432	648,135	648,135	647,936	590,980	590,980	590,980	590,980	590,980	590,980	

(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 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					¢ / kWh			
Line No.	Month	Type	Total KWH Sold	KWH From Own Generation	Fuel Costs	Total Costs	Total $ for Fuel Adjustment	Total Cost ($)
	JANUARY							
1		Other Power Sales	241,780,271	241,780,271	2.55	2.73	6,171,223	6,607,603
2		Economy Sales	5,569,027	5,569,027	2.40	3.14	133,849	174,861
3		Gain on Economy Sales	0	0	0.00	0.00	10,302	10,302
4		TOTAL ACTUAL SALES	247,349,298	247,349,298	2.55	2.75	6,315,374	6,792,766
	FEBRUARY							
5		Other Power Sales	172,603,816	172,603,816	2.14	2.32	3,694,345	4,002,212
6		Economy Sales	6,861,897	6,861,897	1.97	2.68	134,925	183,751
7		Gain on Economy Sales	0	0	0.00	0.00	18,333	18,333
8		TOTAL ACTUAL SALES	179,465,713	179,465,713	2.14	2.34	3,847,603	4,204,296
	MARCH							
9		Other Power Sales	463,829,900	463,829,900	2.52	2.72	11,675,998	12,617,331
10		Economy Sales	4,367,129	4,367,129	2.42	3.35	105,746	146,217
11		Gain on Economy Sales	0	0	0.00	0.00	7,636	7,636
12		TOTAL ACTUAL SALES	468,197,029	468,197,029	2.52	2.73	11,789,380	12,771,184
	APRIL							
13		Other Power Sales	99,028,024	99,028,024	2.53	2.75	2,502,824	2,719,726
14		Economy Sales	4,916,214	4,916,214	2.50	2.31	122,681	113,800
15		Gain on Economy Sales	0	0	0.00	0.00	(32,574)	(32,574)
16		TOTAL ACTUAL SALES	103,944,238	103,944,238	2.49	2.69	2,592,931	2,800,952
	MAY							
17		Other Power Sales	160,825,925	160,825,925	2.99	3.27	4,804,046	5,251,478
18		Economy Sales	2,917,380	2,917,380	1.89	3.90	55,208	113,905
19		Gain on Economy Sales	0	0	0.00	0.00	(26,894)	(26,894)
20		TOTAL ACTUAL SALES	163,743,305	163,743,305	2.95	3.26	4,832,360	5,338,489
	JUNE							
21		Other Power Sales	64,581,122	64,581,122	2.33	2.54	1,507,172	1,642,988
22		Economy Sales	4,398,577	4,398,577	4.10	3.94	180,452	173,114
23		Gain on Economy Sales	0	0	0.00	0.00	27,566	27,566
24		TOTAL ACTUAL SALES	68,979,699	68,979,699	2.49	2.67	1,715,190	1,843,668

Schedule E-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					¢ / kWh			
Line No.	Month	Type	Total KWH Sold	KWH From Own Generation	Fuel Costs	Total Costs	Total $ for Fuel Adjustment	Total Cost ($)
	JULY							
1		Other Power Sales	456,556,000	456,556,000	2.57	2.96	11,729,149	13,532,541
2		Economy Sales	8,426,000	8,426,000	2.75	3.15	231,470	265,081
3		Gain on Economy Sales	0	0	0.00	0.00	29,000	29,000
4		TOTAL ESTIMATED SALES	464,982,000	464,982,000	2.58	2.97	11,989,619	13,826,622
	AUGUST							
5		Other Power Sales	569,637,000	569,637,000	2.48	2.89	14,113,842	16,464,662
6		Economy Sales	10,476,000	10,476,000	2.72	3.11	284,426	325,717
7		Gain on Economy Sales	0	0	0.00	0.00	30,000	30,000
8		TOTAL ESTIMATED SALES	580,113,000	580,113,000	2.49	2.90	14,428,268	16,820,379
	SEPTEMBER							
9		Other Power Sales	568,899,000	568,899,000	2.42	2.77	13,750,408	15,775,056
10		Economy Sales	7,986,000	7,986,000	2.54	2.87	202,462	229,389
11		Gain on Economy Sales	0	0	0.00	0.00	20,000	20,000
12		TOTAL ESTIMATED SALES	576,885,000	576,885,000	2.42	2.78	13,972,870	16,024,445
	OCTOBER							
13		Other Power Sales	412,356,000	412,356,000	2.22	2.60	9,149,976	10,717,579
14		Economy Sales	9,424,000	9,424,000	2.32	2.68	218,248	252,204
15		Gain on Economy Sales	0	0	0.00	0.00	10,000	10,000
16		TOTAL ESTIMATED SALES	421,780,000	421,780,000	2.22	2.60	9,378,224	10,979,783
	NOVEMBER							
17		Other Power Sales	437,478,000	437,478,000	2.08	2.38	9,113,977	10,399,543
18		Economy Sales	7,339,000	7,339,000	2.20	2.50	161,299	183,467
19		Gain on Economy Sales	0	0	0.00	0.00	12,000	12,000
20		TOTAL ESTIMATED SALES	444,817,000	444,817,000	2.09	2.38	9,287,276	10,595,010
	DECEMBER							
21		Other Power Sales	480,458,000	480,458,000	2.30	2.69	11,035,078	12,923,125
22		Economy Sales	11,859,000	11,859,000	2.42	2.78	287,346	329,788
23		Gain on Economy Sales	0	0	0.00	0.00	18,000	18,000
24		TOTAL ESTIMATED SALES	492,317,000	492,317,000	2.30	2.70	11,340,424	13,270,913
	TOTAL							
25		Other Power Sales	4,128,033,058	4,128,033,058	2.40	2.73	99,248,038	112,653,844
26		Economy Sales	84,540,224	84,540,224	2.51	2.95	2,118,112	2,491,294
27		Gain on Economy Sales	0	0	0.00	0.00	123,369	123,369
28		TOTAL ESTIMATED SALES	4,212,573,282	4,212,573,282	2.41	2.74	101,489,520	115,268,507

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 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Month	Purchased From	Type & Schedule	Total KWH Purchased	Other Utilities	KWH for Interruptible	KWH for Firm	¢ / kWh Fuel Cost	¢ / kWh 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 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 201

(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	¢ / kWh Total Cost	Total $ for Fuel Adj
1	JANUARY	Total		24,261,384			None	2.63	0.00	639,170
2	FEBRUARY	Total		21,465,759			None	2.44	0.00	523,202
3	MARCH	Total		18,894,616			None	2.63	0.00	497,243
4	APRIL	Total		17,246,654			None	2.58	0.00	444,567
5	MAY	Total		17,704,864			None	2.94	0.00	520,568
6	JUNE	Total		12,858,008			None	2.63	0.00	338,094
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			112,431,285				2.64	0.00	2,962,844

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Schedule E-9
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ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(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	39,639,612	2.40	951,673
2		Economy Purchases	2,255,142	3.56	80,362
3		Other Purchases	372,458,611	3.48	12,950,287
4		TOTAL ACTUAL PURCHASES	414,353,365	3.37	13,982,322
	FEBRUARY				
5		Southern Co. Interchange	32,014,689	2.07	662,802
6		Economy Purchases	7,284,750	2.76	201,075
7		Other Purchases	411,396,518	3.06	12,581,968
8		TOTAL ACTUAL PURCHASES	450,695,957	2.98	13,445,846
	MARCH				
9		Southern Co. Interchange	8,310,962	2.15	178,300
10		Economy Purchases	9,333,090	3.61	336,683
11		Other Purchases	598,908,854	3.03	18,163,317
12		TOTAL ACTUAL PURCHASES	616,552,906	3.03	18,678,300
	APRIL				
13		Southern Co. Interchange	173,103,958	2.69	4,660,258
14		Economy Purchases	6,819,537	2.66	181,266
15		Other Purchases	263,005,229	3.52	9,266,437
16		TOTAL ACTUAL PURCHASES	442,928,724	3.19	14,107,961
	MAY				
17		Southern Co. Interchange	42,064,777	2.84	1,195,202
18		Economy Purchases	27,003,613	3.29	889,366
19		Other Purchases	536,183,756	2.96	15,856,947
20		TOTAL ACTUAL PURCHASES	605,252,146	2.96	17,941,515
	JUNE				
21		Southern Co. Interchange	67,977,827	2.53	1,720,005
22		Economy Purchases	18,737,282	3.05	570,838
23		Other Purchases	559,781,593	2.82	15,803,847
24		TOTAL ACTUAL PURCHASES	646,496,702	2.80	18,094,690

Schedule E-9
Page 2 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

(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	87,000	2.76	2,399
2		Economy Purchases	5,777,000	3.20	184,944
3		Other Purchases	698,534,000	2.60	18,139,000
4		TOTAL ESTIMATED PURCHASES	704,398,000	2.60	18,326,343
	AUGUST				
5		Southern Co. Interchange	1,157,000	3.51	40,605
6		Economy Purchases	6,163,000	3.16	194,870
7		Other Purchases	698,285,000	2.61	18,214,000
8		TOTAL ESTIMATED PURCHASES	705,605,000	2.61	18,449,475
	SEPTEMBER				
9		Southern Co. Interchange	1,775,000	2.63	46,652
10		Economy Purchases	4,537,000	2.79	126,735
11		Other Purchases	673,928,000	2.63	17,701,000
12		TOTAL ESTIMATED PURCHASES	680,240,000	2.63	17,874,387
	OCTOBER				
13		Southern Co. Interchange	4,007,000	2.36	94,613
14		Economy Purchases	3,792,000	2.43	92,175
15		Other Purchases	409,855,000	3.05	12,491,000
16		TOTAL ESTIMATED PURCHASES	417,654,000	3.04	12,677,788
	NOVEMBER				
17		Southern Co. Interchange	8,060,000	2.71	218,402
18		Economy Purchases	3,227,000	2.39	77,011
19		Other Purchases	662,314,000	2.76	18,298,000
20		TOTAL ESTIMATED PURCHASES	673,601,000	2.76	18,593,413
	DECEMBER				
21		Southern Co. Interchange	362,000	2.82	10,198
22		Economy Purchases	3,611,000	2.79	100,655
23		Other Purchases	642,128,000	2.77	17,795,000
24		TOTAL ESTIMATED PURCHASES	646,101,000	2.77	17,905,853
	TOTAL FOR PERIOD				
25		Southern Co. Interchange	378,559,825	2.58	9,781,109
26		Economy Purchases	98,540,414	3.08	3,035,980
27		Other Purchases	6,526,778,561	2.87	187,260,803
28		TOTAL ACT/EST PURCHASES	7,003,878,800	2.86	200,077,892

Totals may not add due to rounding

Schedule CCE-1A

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP

TO BE INCLUDED IN THE PERIOD JANUARY 2020 - DECEMBER 2020

Line No.	Description	Total
1	Estimated over/(under)-recovery, January 2019 - December 2019 (Schedule CCE-1B, line 16 + 19)	$ (622,746)
2	Final over/(under)-recovery, January 2018 - December 2018 (Exhibit CSB-1, Schedule CCA-1, line 3)	384,798
3	Total Over/(Under)-Recovery (Line 1 + 2) (To be included in January 2020 - December 2020)	$ (237,948)
4	Jurisdictional kWh sales, January 2020 - December 2020	10,951,029,000
5	True-up Factor (Line 3 / Line 4) x 100 (¢/kWh)	0.0022

SCHEDULE CCE-1B

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED TRUE-UP AMOUNT
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

Line No.	Line Descritpiton	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Projection	August Projection	September Projection	October Projection	November Projection	December Projection	TOTAL
1	IIC Payments/(Receipts)	24,045	16,194	(2,995)	(3,628)	(2,995)	(2,995)	0	0	0	0	0	0	27,626
2	Other Capacity Payments / (Receipts)	7,161,383	7,181,450	7,181,449	7,181,449	7,266,193	7,198,831	7,163,330	7,163,330	7,163,330	7,163,330	7,163,330	7,163,330	86,150,733
3	Transmission Revenue	(726)	(541)	(541)	(681)	(151)	(311)	(500)	(500)	(500)	(500)	(500)	(500)	(5,951)
4	Scherer/Flint Credit	(682,078)	(610,980)	(589,922)	(533,987)	(720,007)	(651,768)	(775,216)	(798,886)	(851,222)	(857,561)	(866,108)	(785,065)	(8,722,800)
5	Total Net Capacity Payments/(Receipts)	6,502,624	6,586,123	6,587,991	6,643,153	6,543,040	6,543,757	6,387,614	6,363,944	6,311,608	6,305,269	6,296,722	6,377,765	77,449,608
6	Jurisdictional %	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
7	Jurisdictional Capacity Payments/(Receipts)	6,319,430	6,400,577	6,402,392	6,456,000	6,358,708	6,359,404	6,207,660	6,184,657	6,133,795	6,127,635	6,119,329	6,198,089	75,267,676
8	Retail KWH Sales							1,182,325,000	1,171,710,000	1,004,542,000	848,931,000	731,492,000	827,032,000	
9	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.672	0.672	0.672	0.672	0.672	0.672	
10	Capacity Cost Recovery Revenues	5,699,684	4,374,885	4,856,216	4,880,950	6,633,211	7,475,622	7,945,224	7,873,891	6,750,522	5,704,816	4,915,626	5,557,655	72,668,302
11	Revenue Taxes (Line 10 x .00072)	4,104	3,150	3,496	3,514	4,776	5,382	5,721	5,669	4,860	4,107	3,539	4,002	52,320
12	True-Up Provision	169,499	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	2,034,010
13	Capacity Cost Recovery Revenues (net of Revenue Taxes)	5,865,079	4,541,236	5,022,220	5,046,937	6,797,936	7,639,741	8,109,004	8,037,723	6,915,163	5,870,210	5,081,588	5,723,154	74,649,992
14	Over/(Under) Recovery	(454,351)	(1,859,341)	(1,380,172)	(1,409,063)	439,228	1,280,337	1,901,344	1,853,066	781,368	(257,425)	(1,037,741)	(474,935)	(617,685)
15	Interest Provision	4,241	1,576	(2,044)	(5,256)	(6,483)	(4,996)	(2,182)	1,115	3,336	3,521	1,948	163	(5,061)
16	Total Estimated True-Up for the Period													(622,746)
17	Beginning Balance True-Up & Interest Provision	2,418,808	1,799,199	(228,067)	(1,779,784)	(3,363,604)	(3,100,360)	(1,994,520)	(264,859)	1,419,821	2,035,024	1,611,619	406,325	2,418,808
18	True-Up Collected/(Refunded)	(169,499)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(2,034,010)
19	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
20	End of Period TOTAL Net True-Up	1,799,199	(228,067)	(1,779,784)	(3,363,604)	(3,100,360)	(1,994,520)	(264,859)	1,419,821	2,035,024	1,611,619	406,325	(237,948)	(237,948)

SCHEDULE CCE-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

Line No.	Line Descritpiton	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Projection	August Projection	September Projection	October Projection	November Projection	December Projection	TOTAL
1	IIC Payments / (Receipts)	24,045	16,194	(2,995)	(3,628)	(2,995)	(2,995)	-	-	-	-	-	-	27,626
2	Other Capacity Payments / (Receipts)	7,161,383	7,181,450	7,181,449	7,181,449	7,266,193	7,198,831	7,163,330	7,163,330	7,163,330	7,163,330	7,163,330	7,163,330	86,150,733
3	Transmission Revenue	(726)	(541)	(541)	(681)	(151)	(311)	(500)	(500)	(500)	(500)	(500)	(500)	(5,951)
4	Scherer/Flint Credit	(682,078)	(610,980)	(589,922)	(533,987)	(720,007)	(651,768)	(775,216)	(798,886)	(851,222)	(857,561)	(866,108)	(785,065)	(8,722,800)
5	Total Capacity Payments/(Receipts)	6,502,624	6,586,124	6,587,991	6,643,153	6,543,040	6,543,757	6,387,614	6,363,944	6,311,608	6,305,269	6,296,722	6,377,765	77,449,608
6	Jurisdictional %	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
7	Total Jurisdictional Recovery Amount	6,319,430	6,400,578	6,402,392	6,456,000	6,358,708	6,359,404	6,207,660	6,184,657	6,133,795	6,127,635	6,119,329	6,198,088	75,267,676
8	Jurisdictional Capacity Cost Recovery Revenues (Net of Taxes)	5,695,580	4,371,735	4,852,719	4,877,436	6,628,435	7,470,240	7,939,503	7,868,222	6,745,662	5,700,709	4,912,087	5,553,654	72,615,982
9	True-Up Provision	169,499	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	2,034,010
10	Jurisdictional Capacity Cost Recovery Revenue	5,865,079	4,541,236	5,022,220	5,046,937	6,797,936	7,639,741	8,109,004	8,037,723	6,915,163	5,870,210	5,081,588	5,723,155	74,649,992
11	Over/(Under) Recovery	(454,351)	(1,859,342)	(1,380,172)	(1,409,063)	439,228	1,280,337	1,901,344	1,853,066	781,368	(257,425)	(1,037,741)	(474,933)	(617,685)
12	Interest Provision	4,241	1,576	(2,044)	(5,256)	(6,483)	(4,996)	(2,182)	1,115	3,336	3,521	1,948	163	(5,061)
13	Beginning Balance True-Up & Interest Provision	2,418,808	1,799,199	(228,068)	(1,779,785)	(3,363,605)	(3,100,361)	(1,994,521)	(264,860)	1,419,820	2,035,023	1,611,618	406,324	2,418,808
14	True-Up Collected/(Refunded)	(169,499)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(2,034,010)
15	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
16	End of Period Total Net True-Up ($)	1,799,199	(228,068)	(1,779,785)	(3,363,605)	(3,100,361)	(1,994,521)	(264,860)	1,419,820	2,035,023	1,611,618	406,324	(237,948)	(237,948)

SCHEDULE CCE-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

Line No.	Line Descritpiton	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Projection	August Projection	September Projection	October Projection	November Projection	December Projection	TOTAL
1	Beginning True-Up Amount	2,418,808	1,799,199	(228,068)	(1,779,785)	(3,363,605)	(3,100,361)	(1,994,521)	(264,860)	1,419,820	2,035,023	1,611,618	406,324	
2	Ending True-Up Amount Before Interest	1,794,958	(229,644)	(1,777,741)	(3,358,349)	(3,093,878)	(1,989,525)	(262,678)	1,418,705	2,031,687	1,608,097	404,376	(238,110)	
3	Total Beginning & Ending True-Up Amount (Lines 1 + 2)	4,213,766	1,569,555	(2,005,809)	(5,138,134)	(6,457,483)	(5,089,886)	(2,257,199)	1,153,845	3,451,507	3,643,120	2,015,994	168,214	
4	Average True-Up Amount	2,106,883	784,778	(1,002,905)	(2,569,067)	(3,228,742)	(2,544,943)	(1,128,600)	576,923	1,725,754	1,821,560	1,007,997	84,107	
5	Interest Rate - First Day of Reporting Business Month	2.42%	2.41%	2.41%	2.48%	2.43%	2.39%	2.32%	2.32%	2.32%	2.32%	2.32%	2.32%	
6	Interest Rate - First Day of Subsequent Business Month	2.41%	2.41%	2.48%	2.43%	2.39%	2.32%	2.32%	2.32%	2.32%	2.32%	2.32%	2.32%	
7	Total Interest Rate (Lines 5 + 6)	4.83%	4.82%	4.89%	4.91%	4.82%	4.71%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	
8	Average Interest Rate	2.415%	2.410%	2.445%	2.455%	2.410%	2.355%	2.320%	2.320%	2.320%	2.320%	2.320%	2.320%	
9	Monthly Average Interest Rate	0.2013%	0.2008%	0.2038%	0.2046%	0.2008%	0.1963%	0.1933%	0.1933%	0.1933%	0.1933%	0.1933%	0.1933%	
10	Interest Provision For the Month (Lines 4 X 9)	4,241	1,576	(2,044)	(5,256)	(6,483)	(4,996)	(2,182)	1,115	3,336	3,521	1,948	163	(5,061)

SCHEDULE CCE-4

Gulf Power Company
2019 Capacity Contracts
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

	(A)	(B)	(C)
		Term	Contract
Contract/Counterparty	Start	End [1]	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 Rainbow Energy Marketing Corporation	1/1/2019	2/22/2019	Other
7 PowerSouth Energy Cooperative	4/14/2019	4/15/2019	Other

	Capacity Costs 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	TOTAL
9	Southern Intercompany Interchange	0	0	0	0	0	0	0	0	0	0	0	0	0
10	*PPAs*													
11	Shell Energy N.A. (U.S.), LP	[redacted]												
12	*Other*													
13	South Carolina PSA	[redacted]												
14	Rainbow Energy Marketing Corporation	[redacted]												
15	PowerSouth Energy Cooperative	[redacted]												
16	Total		7,197,644	7,178,454		7,263,198	7,195,836	7,163,330	7,163,330	7,163,330	7,163,330	7,163,330	7,163,330	

	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
17	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
18	*PPAs*												
19	Shell Energy N.A. (U.S.), LP	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0
20	*Other*												
21	South Carolina PSA	[redacted]											
22	Rainbow Energy Marketing Corporation	[redacted]											
23	PowerSouth Energy Cooperative	[redacted]											

24 (1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
SCHERER/FLINT CREDIT CALCULATION
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

Line No.	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	TOTAL
1	Projected Flint Revenue	1,544,611	1,015,516	1,015,496	1,261,844	1,787,396	1,552,235	1,933,012	1,920,612	1,858,846	1,755,105	1,650,730	1,731,272	19,026,675
2	Less: Environmental Flint Expenses	350,723	404,536	427,116	351,696	411,570	386,944	394,688	382,902	379,652	369,613	369,602	346,254	4,575,296
3	Less: Flint Fuel Costs	511,810	-	(1,542)	376,161	655,820	513,523	763,108	738,824	627,972	527,931	415,020	599,953	5,728,579
4	Total Flint Revenue Available for Capacity Credit	**682,078**	**610,980**	**589,922**	**533,987**	**720,007**	**651,768**	**775,216**	**798,886**	**851,222**	**857,561**	**866,108**	**785,065**	**8,722,800**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 55
PARTY: GULF POWER – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-4

Docket No. 20190001-EI
2019 Act/Est Schedules
Exhibit No. (CSB-4), Page 1 of 1

SCHEDULE E-1

GULF POWER COMPANY
FUEL COST RECOVERY CALCULATION

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(2)	(3)	(4)	(5)
Line No.	Description	$	kWh	¢ / kWh
1	Fuel Cost of System Net Generation (E-3)	263,829,683	9,306,904,000	2.8348
2	Other Generation (E-3)	1,844,483	67,440,000	2.7350
3	Hedging Settlement (E-2)	1,093,590	0	N/A
4	**Total Cost of Generated Power**	266,767,756	9,374,344,000	2.8457
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E-7)	0	0	
6	Energy Cost of Other Econ. Purch. (E-9))	216,369,405	7,560,995,000	2.8617
7	Energy Payments to Qualifying Facilities (E-8)	0	0	
8	**Total Cost of Purchased Power**	216,369,405	7,560,995,000	2.8617
9	**Total Available kWh** (Lines 4 + 8)		16,935,339,000	
10	Fuel Cost of Economy Sales (E-6)	(2,817,048)	(109,487,000)	2.5730
11	Gain on Economy Sales (E-6)	(223,000)	0	N/A
12	Fuel Cost of Other Power Sales (E-6)	(126,186,576)	(5,297,893,000)	2.3818
13	**Total Fuel Cost & Gains on Power Sales**	(129,226,624)	(5,407,380,000)	2.3898
14	Net Inadvertant Interchange			
15	**Total Fuel & Net Power Trans.** (Lines 4+8+13)	353,910,537	11,527,959,000	3.0700
16	Company Use *	465,627	15,167,000	3.0700
17	T & D Losses *	17,246,124	561,763,000	3.0700
18	**System kWh Sales**	353,910,537	10,951,029,000	3.2318
19	Wholesale kWh Sales	0	0	#N/A
20	Jurisdictional kWh Sales	353,910,537	10,951,029,000	3.2318
20a	Jurisdictional Line Loss Multiplier	1.0012		1.0012
21	Jurisdictional kWh Sales Adjusted for Line Losses	354,335,230	10,951,029,000	3.2356
22	**True-Up ****	666,833	10,951,029,000	0.0061
23	**Total Jurisdictional Fuel Cost**	355,002,063	10,951,029,000	3.2417
24	Revenue Tax Factor			1.00072
25	Fuel Factor Adjusted For Revenue Taxes	355,257,664	10,951,029,000	3.2441
26	GPIF Reward/(Penalty) **	10,384	10,951,029,000	0.0001
27	Fuel Factor Adjusted for GPIF	355,268,048	10,951,029,000	3.2442
28	Fuel Factor Adjusted for GPIF	355,268,048	10,951,029,000	3.2442
29	**Fuel Factor Rounded to Nearest .001 (¢/kWh)**			**3.244**

*For informational purposes only
** Calculation Based on Jurisdictional kWh Sales

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 56
PARTY: GULF POWER – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-5

SCHEDULE E-1A

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

Line No.	Description	Annual Total
1	Estimated over/(under)-recovery, January 2019 - December 2019 (Schedule E-1B, page 2, line C9)	($5,178,904)
2	Final over/(under)-recovery, January 2018 - December 2018 (Exhibit CSB-1, Schedule 1, Line 3)	$4,512,071
3	Total over/(under)-recovery (Lines 1 + 2) To be included in January 2020 - December 2020 (Schedule E1, Line 23)	($666,833)
4	Jurisdictional MWh sales For the period: January 2020 - December 2020	10,951,029
5	True-up Factor (Line 3 / Line 4) x 100 (¢ / kWh)	0.0061

Schedule E-1B

GULF POWER COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

	(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 Projection	August Projection	September Projection	October Projection	November Projection	December Projection	Total Period
A	1	Fuel Cost of System Generation	23,179,762.07	10,379,345.74	19,124,590.38	16,011,423.76	22,744,884.73	21,829,691.65	32,355,942.00	33,932,386.00	28,876,538.00	26,477,294.00	16,096,467.00	20,688,685.00	271,697,010.33
	1a	Fuel Cost of Hedging Settlement	142,790.00	454,190.00	496,940.00	560,840.00	626,990.00	596,840.00	700,340.00	761,540.00	772,790.00	757,490.00	722,990.00	619,640.00	7,213,380.00
	1b	Scherer/Flint Credit	(511,810.14)	0.00	1,541.56	(376,161.34)	(655,819.50)	(513,522.52)	(763,107.73)	(738,824.35)	(627,971.57)	(527,931.36)	(415,019.64)	(599,952.54)	(5,728,579.13)
	2	Fuel Cost of Power Sold	(6,315,373.90)	(3,847,602.75)	(11,789,380.30)	(2,592,931.79)	(4,832,360.33)	(1,715,190.22)	(11,989,619.00)	(14,428,268.00)	(13,972,870.00)	(9,378,224.00)	(9,287,276.00)	(11,340,424.00)	(101,489,520.29)
	3	Fuel Cost of Purchased Power	13,982,321.47	13,445,845.38	18,678,300.26	14,107,961.11	17,941,515.70	18,094,689.47	18,326,343.00	18,449,475.00	17,874,387.00	12,677,788.00	18,593,413.00	17,905,853.00	200,077,892.39
	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	639,169.63	523,201.78	497,243.49	444,567.42	520,567.74	338,094.18	0.00	0.00	0.00	0.00	0.00	0.00	2,962,844.24
	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	177,352.92	149,457.86	237,961.29	190,881.88	171,705.71	158,454.96	156,204.00	156,204.00	151,173.00	156,204.00	151,173.00	156,204.00	2,012,976.62
	6	Adjustments to Fuel Cost	0.00	(311,628.74)	(248,867.42)	0.00	(6,380.84)	105,679.30	0.00	0.00	0.00	0.00	0.00	0.00	(461,197.70)
	7	TOTAL FUEL & NET POWER TRANSACTIONS	31,294,212.05	20,792,809.27	26,998,329.26	28,346,581.04	36,511,103.21	38,894,736.82	38,786,102.27	38,132,512.65	33,074,046.43	30,162,620.64	25,861,747.36	27,430,005.46	376,284,806.46
B	1	Jurisdictional kWh Sales	864,788,358	670,334,830	747,527,553	754,647,350	1,008,838,581	1,116,743,905	1,182,325,000	1,171,710,000	1,004,542,000	848,931,000	731,492,000	827,032,000	10,928,912,577
	2	Non-Jurisdictional kWh Sales	24,797,417	18,315,462	20,326,293	19,981,205	27,436,089	27,436,089	30,780,000	30,334,000	26,676,000	22,945,000	21,493,000	25,124,000	295,644,555
	3	TOTAL SALES (Lines B1 + B2)	889,585,775	688,650,292	767,853,846	774,628,555	1,036,274,670	1,144,179,994	1,213,105,000	1,202,044,000	1,031,218,000	871,876,000	752,985,000	852,156,000	11,224,557,132
	4	Jurisdictional % of Total Sales (Line B1/B3)	97.2125%	97.3404%	97.3528%	97.4205%	97.3524%	97.6021%	97.4627%	97.4765%	97.4132%	97.3683%	97.1456%	97.0517%	
C	1	Jurisdictional Fuel Recovery Revenue (1) (Net of Revenue Taxes)	25,873,403.53	19,672,728.02	22,537,774.01	22,548,788.96	30,354,039.24	34,011,265.87	35,798,672.46	35,477,269.37	30,415,723.28	25,704,102.35	22,148,260.85	25,041,040.05	329,583,067.98
	2	True-Up Provision	1,950,781.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	1,950,778.00	23,409,339.00
	2a	Incentive Provision	21,386.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	21,391.00	256,687.00
	2b	Retail Tax Savings Credit	674,592.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	674,590.00	8,095,082.00
	3	FUEL REVENUE APPLICABLE TO PERIOD	28,520,162.53	22,319,487.02	25,184,533.01	25,195,547.96	33,000,798.24	36,658,024.87	38,445,431.46	38,124,028.37	33,062,482.28	28,350,861.35	24,795,019.85	27,687,799.05	361,344,175.98
	4	Fuel & Net Power Transactions (Line A7)	31,294,212.05	20,792,809.27	26,998,329.26	28,346,581.04	36,511,103.21	38,894,736.82	38,786,102.27	38,132,512.65	33,074,046.43	30,162,620.64	25,861,747.36	27,430,005.46	$376,284,806.46
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0012)	30,458,392	20,264,091	26,315,170	27,648,519	35,587,089	38,007,634	37,847,344.88	37,214,842.98	32,257,149.18	29,404,073.55	25,153,697.90	26,653,232.15	$366,811,236.53
	6	Over/(Under) Recovery (Line C3-C5)	(1,938,229.62)	2,055,395.54	(1,130,636.83)	(2,452,971.48)	(2,586,290.32)	(1,349,609.55)	598,086.58	909,185.39	805,333.10	(1,053,212.20)	(358,678.05)	1,034,566.90	($5,467,060.540)
	7	Interest Provision	52,291.51	48,467.09	46,256.62	38,875.52	29,254.97	20,964.32	16,187.25	13,904.47	11,817.57	7,829.99	2,709.68	(403)	$288,156.30
	8	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	$0
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2019 - DECEMBER 2019**													($5,178,904.24)

* (Gain)/Loss on sales of natural gas and contract dispute litigation

Notes 1: Projected Revenues based on the current approved 2019 Fuel Factor excluding revenue taxes of: 3.0278 ¢/KWH

Schedule E-1B-1

GULF POWER COMPANY
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL COST RECOVERY FACTOR

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
		Dollars				kWh				¢/kWh			
Line No.	Description	Estimated Actual	Estimated Original	Difference Amount	Difference %	Estimated Actual	Estimated Original	Difference Amount	Difference %	Estimated Actual	Estimated Original	Difference Amount	Difference %
1	Fuel Cost of System Net Generation	271,697,010	256,848,474	14,848,536	5.78	9,045,489,480	8,888,872,000	156,617,480	1.76	3.0037	2.8896	0.1141	3.95
1a	Fuel Cost of Hedging Settlement	7,213,380	6,701,880	511,500	7.63	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1b	Scherer/Flint Credit	(5,728,579)	(5,587,895)	(140,684)	2.52	(200,390,000)	(209,718,000)	9,328,000	(4.45)	0.0000	2.6645	(2.6645)	(100.00)
2	Other Generation	2,012,977	2,390,125	(377,148)	(15.78)	73,609,520	81,352,000	(7,742,480)	(9.52)	2.7347	2.9380	(0.2033)	(6.92)
3	Adjustments to Fuel Cost	(461,198)	0	(461,198)	-	0	0	0	0	N/A	N/A	N/A	N/A
4	**Total Cost of Generated Power**	274,733,590	260,352,584	14,381,006	5.52	8,918,709,000	8,760,506,000	158,203,000	1.81	3.0804	2.9719	0.1085	3.65
5	Energy Cost of Other Economy Purchases (Nonbroker)	200,077,892	214,200,334	(14,122,442)	(6.59)	7,003,878,800	7,318,073,000	(314,194,200)	(4.29)	2.8567	2.9270	(0.0703)	(2.40)
6	Energy Payments to Qualifying Facilities	2,962,844	0	2,962,844	-	112,431,285	0	112,431,285	-	2.6352	0.0000	2.6352	100.00
7	**Total Cost of Purchased Power**	203,040,737	214,200,334	(11,159,597)	(5.21)	7,116,310,085	7,318,073,000	(201,762,915)	(2.76)	2.8532	2.9270	(0.0738)	(2.52)
8	**Total Available** (Line 4 + Line 7)	477,774,327	474,552,918	3,221,409	0.68	16,035,019,085	16,078,579,000	(43,559,915)	(0.27)	2.9796	2.9515	0.0281	0.95
9	Fuel Cost of Economy Sales	(2,118,112)	(2,762,145)	644,033	(23.32)	(84,540,224)	(109,939,000)	25,398,776	(23.10)	2.5054	2.5124	(0.0070)	(0.28)
10	Gain on Economy Sales	(123,369)	(104,000)	(19,369)	18.62	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	Fuel Cost of Other Power Sales	(99,248,038)	(102,387,084)	3,139,046	(3.07)	(4,128,033,058)	(4,307,932,000)	179,898,942	(4.18)	2.4042	2.3767	0.0275	1.16
12	**Total Gains on Power Sales**	(101,489,520)	(105,253,229)	3,763,710	(3.58)	(4,212,573,282)	(4,417,871,000)	205,297,718	(4.65)	2.4092	2.3824	0.0268	1.12
13	**Total Fuel & Net Power Transactions**	376,284,806	369,299,689	6,985,117	1.89	11,822,445,803	11,660,708,000	161,737,803	1.39	3.1828	3.1670	0.0158	0.50
14	Company Use *	447,036	490,410	(43,374)	(8.84)	14,045,371	15,485,000	(1,439,629)	(9.30)	3.1828	3.1670	0.0158	0.50
15	T & D Losses *	18,582,565	18,191,090	391,475	2.15	583,843,300	574,395,000	9,448,300	1.64	3.1828	3.1670	0.0158	0.50
16	TERRITORIAL (SYSTEM) SALES	376,284,806	369,299,689	6,985,117	1.89	11,224,557,132	11,070,828,000	153,729,132	1.39	3.3523	3.3358	0.0165	0.49
17	Wholesale Sales	9,910,997	10,049,464	(138,467)	(1.38)	295,644,555	301,261,000	(5,616,445)	(1.86)	3.3523	3.3358	0.0165	0.49
18	Jurisdictional Sales	366,373,809	359,250,225	7,123,584	1.98	10,928,912,577	10,769,567,000	159,345,577	1.48	3.3523	3.3358	0.0165	0.49
19	Jurisdictional Sales Adj. for Line Losses (Line 18 x 1.0012)	366,811,237	359,681,325	7,129,912	1.98	10,928,912,577	10,769,567,000	159,345,577	1.48	3.3563	3.3398	0.0165	0.49
20	TRUE-UP **	(23,409,339)	(23,409,339)	0	0.00	10,928,912,577	10,769,567,000	159,345,577	1.48	(0.2142)	(0.2174)	0.0032	(1.47)
21	TOTAL JURISDICTIONAL FUEL COST	343,401,898	336,271,986	7,129,912	2.12	10,928,912,577	10,769,567,000	159,345,577	1.48	3.1421	3.1224	0.0197	0.63
22	Fuel Factor Adjusted for Revenue Taxes									3.1444	3.1246	0.0197	0.63
23	GPIF Reward / (Penalty) **	(256,872)	(256,872)	0	0.00	10,928,912,577	10,769,567,000	159,345,577	1.48	(0.0024)	(0.0024)	0.0000	0.00
27	Tax Savings Credit	(8,095,082)	(9,946,000)	1,850,918	(18.61)	10,928,912,577	10,769,567,000	159,345,577	1.48	(0.0741)	(0.0924)	0.0183	19.81
28	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.0679	3.0298	0.0381	1.26
29	**FUEL FACTOR ROUNDED TO NEAREST .001(¢/kWh)**									3.0680	3.0300	0.0380	1.25

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

SCHEDULE E-1C

GULF POWER COMPANY
CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

Line No.	Description		Annual Total
1	TOTAL AMOUNT OF ADJUSTMENTS:		
A	Generating Performance Incentive Reward/(Penalty)	$	10,384
B	True-up (Over)/Under Recovered	$	666,833
2	Jurisdictional MWh sales		
	For the period: January 2020 - December 2020		10,951,029
3	ADJUSTMENT FACTORS (¢ per kWh):		
A	Generating Performance Incentive Factor		0.0001
B	True-up Factor		0.0061

SCHEDULE E-1D

GULF POWER COMPANY
DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

Net Energy For Load %

On-Peak	28.91
Off-Peak	71.09
	100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per kWh Sold	3.2318	3.7273	3.0303
Jurisdictional Loss Factor	1.0012	1.0012	1.0012
Jurisdictional Fuel Factor	3.2357	3.7318	3.0339
GPIF	0.0001	0.0001	0.0001
True-Up	0.0061	0.0061	0.0061
TOTAL	3.2419	3.738	3.0401
Revenue Tax Factor	1.00072	1.00072	1.00072
Recovery Factor	3.2442	3.7407	3.0423
Recovery Factor (Rounded to the nearest .001 ¢/kWh)	3.244	3.741	3.042

HOURS:	ON-PEAK	25.13%
	OFF-PEAK	74.87%
		100.00%

SCHEDULE E-1E

GULF POWER COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(2)	(3)	(4)	(5)		(6)	(7)	(8)
						Time Of Use		
Groups	Rate Schedules	Average Factor	Fuel Recovery LossMultipliers	Fuel Recovery Factor		Groups	Time of Use	Factor
A	RS, RSVP, RSTOU	3.244	1.00555	3.262		A	On-Peak	3.762
A	GS, GSD, GSDT, GSTOU	3.244	1.00555	3.262			Off-Peak	3.059
A	OSIII	3.244	1.00555	3.262				
A	SBS (1)	3.244	1.00555	3.262				
B	LP, LPT, SBS (2)	3.244	0.99188	3.218		B	On-Peak	3.711
B	SBS (2)	3.244	0.99188	3.218			Off-Peak	3.017
C	PX,PXT, RTP, SBS (3)	3.244	0.97668	3.168		C	On-Peak	3.654
C	RTP	3.244	0.97668	3.168			Off-Peak	2.971
C	SBS (3)	3.244	0.97668	3.168				
D	OS-I/II	3.244	1.00560	3.236	*	D	On-Peak	N/A
							Off-Peak	N/A

Group D Calculation

* D	On-Peak	3.741 ¢ / kWh	x	0.2513	=	0.940 ¢ / kWh
	Off-Peak	3.042 ¢ / kWh	x	0.7487	=	2.278 ¢ / kWh
						3.218 ¢ / kWh
			Line Loss Multiplier		x	1.00560
						3.236 ¢ / kWh

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 kW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 kW
(3) Includes SBS customers with a Contract Demand over 7,499 kW

SCHEDULE E-2

GULF POWER COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		ESTIMATED												
LINE	LINE DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	$													
1	Fuel Cost of System Generation	24,452,484	19,969,316	13,083,318	14,593,948	22,482,830	32,285,562	32,921,037	33,861,353	17,213,568	18,414,074	15,629,210	18,922,983	263,829,683
1a	Other Generation	156,223	146,158	156,223	151,191	156,223	151,191	156,223	156,223	151,191	156,223	151,191	156,223	1,844,483
2	Fuel Cost of Power Sold	(13,460,337)	(9,932,375)	(10,534,504)	(5,177,491)	(10,427,647)	(14,547,887)	(15,787,353)	(16,922,844)	(5,499,805)	(5,149,782)	(10,669,375)	(11,117,224)	(129,226,624)
3	Fuel Cost of Purchased Power	18,147,632	15,463,578	20,575,813	15,343,323	18,665,758	18,921,208	18,985,391	19,173,381	19,844,785	14,019,957	18,914,698	18,313,881	216,369,405
3a	Demand & Non-Fuel Cost of Pur Powe	0	0	0	0	0	0	0	0	0	0	0	0	0
3b	Qualifying Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Hedging Settlement	352,320	360,570	380,700	0	0	0	0	0	0	0	0	0	1,093,590
6	**Total Fuel & Net Power Trans.** (Sum of Lines 1 - 5)	29,648,322	26,007,247	23,661,550	24,910,971	30,877,164	36,810,074	36,275,298	36,268,113	31,709,739	27,440,472	24,025,724	26,275,863	353,910,537
7	System MWh Sold	881,768	772,423	736,408	756,129	938,298	1,094,766	1,186,135	1,175,626	1,004,436	844,529	734,055	826,456	10,951,029
7a	Jurisdictional % of Total Sales	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000
8	Cost per kWh Sold (¢/kWh)	3.3624	3.3670	3.2131	3.2945	3.2908	3.3624	3.0583	3.0850	3.1570	3.2492	3.2730	3.1793	3.2318
8a	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
8b	Jurisdictional Cost (¢/kWh)	3.3664	3.3710	3.2170	3.2985	3.2947	3.3664	3.0619	3.0887	3.1608	3.2531	3.2769	3.1832	3.2356
9	GPIF (¢/kWh) *	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
10	True-Up (¢/kWh) *	0.0063	0.0072	0.0075	0.0073	0.0059	0.0051	0.0047	0.0047	0.0055	0.0066	0.0076	0.0067	0.0061
11	TOTAL	3.3728	3.3783	3.2247	3.3060	3.3007	3.3716	3.0667	3.0935	3.1664	3.2598	3.2846	3.1900	3.2418
12	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
13	Recovery Factor Adjusted for Taxes	3.3752	3.3807	3.2270	3.3084	3.3031	3.3740	3.0689	3.0957	3.1687	3.2621	3.2870	3.1923	3.2441
14	**Recovery Factor Rounded to the Nearest .001 ¢/kWh**	3.375	3.381	3.227	3.308	3.303	3.374	3.069	3.096	3.169	3.262	3.287	3.192	3.244

* Calculations Based on Jurisdictional kWh Sales

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1) Line No.	(2) Description	(3)	(4) January Estimated	(5) February Estimated	(6) March Estimated	(7) April Estimated	(8) May Estimated	(9) June Estimated	(10) July Estimated	(11) August Estimated	(12) September Estimated	(13) October Estimated	(14) November Estimated	(15) December Estimated	(16) 12 Month Period
	FUEL COST - NET GEN. ($)														
1	LIGHTER OIL (B.L.)		91,023	90,858	50,439	86,130	90,604	90,539	73,783	73,747	73,721	46,411	6,281	46,406	819,942
2	COAL		10,919,496	8,562,187	2,747,654	3,032,400	9,234,243	18,012,556	5,154,486	6,029,815	3,599,117	2,147,251	0	2,000,980	71,440,185
2a	Coal at Scherer		2,806,024	1,801,255	1,715,578	2,241,265	2,701,149	2,826,708	3,258,490	3,203,759	3,023,748	2,428,212	1,651,726	2,629,976	30,287,890
3	GAS - Generation		10,523,338	9,399,316	8,465,288	9,226,200	10,366,185	11,136,283	24,438,211	24,635,853	10,596,113	13,874,021	14,050,334	14,327,442	161,038,584
4	GAS (B.L.)		194,424	192,246	186,180	87,084	172,470	174,534	0	0	0	0	0	0	1,006,938
5	LANDFILL GAS		74,402	69,612	74,402	72,060	74,402	196,133	74,402	74,402	72,060	74,402	72,060	74,402	1,002,739
6	OIL - C.T.		0	0	0	0	0	0	77,888	0	0	0	0	0	77,888
7	TOTAL ($)		24,608,707	20,115,474	13,239,541	14,745,139	22,639,053	32,436,753	33,077,260	34,017,576	17,364,759	18,570,297	15,780,401	19,079,206	265,674,166
	SYSTEM NET GEN. (MWh)														
8	LIGHTER OIL (B.L.)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL		317,511	240,066	74,894	84,718	245,540	514,682	157,244	185,964	110,664	65,569	0	58,594	2,055,446
9a	Coal at Scherer		102,328	66,459	63,840	80,251	97,692	102,739	118,624	117,745	109,265	87,675	58,809	95,375	1,100,802
10	GAS		418,247	384,900	359,035	359,436	392,422	433,375	858,107	854,325	338,955	519,194	546,439	537,381	6,001,816
11	LANDFILL GAS		2,097	1,962	2,097	2,031	2,097	2,031	2,097	2,097	2,031	2,097	2,031	2,097	24,765
12	OIL - C.T.		80	0	72	0	72	0	0	64	128	0	0	0	416
13	Solar		11,638	12,412	16,674	18,060	20,573	18,952	19,512	18,386	16,506	15,970	12,516	9,900	191,099
14	TOTAL (MWH)		851,901	705,799	516,612	544,496	758,396	1,071,779	1,155,584	1,178,581	577,549	690,505	619,795	703,347	9,374,344
	UNITS OF FUEL BURNED														
15	LIGHTER OIL (BBL)		1,018	1,018	564	967	1,018	1,018	830	830	830	521	67	521	9,202
16	COAL (TON)		165,742	123,179	43,696	48,610	121,960	265,156	94,957	111,573	66,866	40,554	0	36,686	1,118,979
17	GAS-all (MCF) (1)		2,973,461	2,679,833	2,436,479	2,410,657	2,822,772	3,104,961	7,430,924	7,459,336	2,732,174	3,859,436	4,283,969	4,129,714	46,323,716
18	OIL - C.T. (BBL)		0	0	0	0	0	0	846	0	0	0	0	0	846
	BTUS BURNED (MMBtu)														
19	COAL + GAS B.L. + OIL B.L.		4,607,428	3,339,245	1,584,102	1,845,076	3,714,470	6,737,115	2,997,543	3,274,336	2,386,269	1,671,238	636,706	1,687,112	34,480,640
20	GAS-Generation (1)		2,972,930	2,673,429	2,425,208	2,428,870	2,819,227	3,107,060	7,579,542	7,608,522	2,786,818	3,936,624	4,369,649	4,212,308	46,920,187
21	OIL - C.T.		0	0	0	0	0	0	4,951	0	0	0	0	0	4,951
22	TOTAL (MMBtu) (1)		7,580,358	6,012,674	4,009,310	4,273,946	6,533,697	9,844,175	10,582,036	10,882,858	5,173,087	5,607,862	5,006,355	5,899,420	81,405,778

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtus are not available due to contract specifications.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1) Line No.	(2) Description	(3)	(4) January Estimated	(5) February Estimated	(6) March Estimated	(7) April Estimated	(8) May Estimated	(9) June Estimated	(10) July Estimated	(11) August Estimated	(12) September Estimated	(13) October Estimated	(14) November Estimated	(15) December Estimated	(16) 12 Month Period
	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		49.27	43.43	26.85	30.30	45.26	57.60	23.87	25.76	38.08	22.20	9.49	21.89	33.68
25	GAS-Generation		49.10	54.53	69.50	66.01	51.74	40.44	74.26	72.49	58.69	75.19	88.16	76.40	64.02
26	LANDFILL GAS		0.25	0.28	0.41	0.37	0.28	0.19	0.18	0.18	0.35	0.30	0.33	0.30	0.26
27	OIL - C.T.		0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.02	0.00	0.00	0.00	0.00
28	Solar		1.37	1.76	3.23	3.32	2.71	1.77	1.69	1.56	2.86	2.31	2.02	1.41	2.04
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 ($/BBL)		89.41	89.25	89.43	89.07	89.00	88.94	88.90	88.85	88.82	89.08	93.75	89.07	89.10
31	COAL ($/TON)		65.88	69.51	62.88	62.38	75.72	67.93	54.28	54.04	53.83	52.95	#N/A	54.54	63.84
32	GAS + B.L. ($/MCF) (1)		3.55	3.52	3.49	3.80	3.68	3.59	3.27	3.28	3.82	3.55	3.24	3.43	3.46
33	OIL - C.T.		0.00	0.00	0.00	0.00	0.00	0.00	92.07	0.00	0.00	0.00	0.00	0.00	92.07
	FUEL COST ($ / MMBtu)														
34	COAL + GAS B.L. + OIL B.L.		3.04	3.19	2.97	2.95	3.28	3.13	2.83	2.84	2.81	2.77	2.60	2.77	3.00
35	GAS-Generation (1)		3.49	3.46	3.43	3.74	3.62	3.54	3.20	3.22	3.75	3.48	3.18	3.36	3.39
36	OIL - C.T.		0.00	0.00	0.00	0.00	0.00	0.00	15.73	0.00	0.00	0.00	0.00	0.00	15.73
37	TOTAL ($/MMBtu) (1)		3.22	3.31	3.24	3.40	3.43	3.26	3.10	3.10	3.31	3.27	3.11	3.19	3.23
	BTU BURNED (Btu / kWh)														
38	COAL + GAS B.L. + OIL B.L.		10,974	10,894	11,418	11,184	10,822	10,912	10,866	10,781	10,850	10,906	#N/A	10,957	10,925
39	GAS-Generation (1)		7,206	7,044	6,864	6,863	7,290	7,262	8,892	8,966	8,358	7,667	8,078	7,923	7,907
40	OIL - C.T.		0	0	0	0	0	0	0	0	0	0	0	0	11,901
41	TOTAL (Btu/kWh) (1)		8,980	8,608	7,880	7,960	8,705	9,281	9,220	9,295	9,076	8,214	8,177	8,482	8,770
	FUEL COST (Cents / kWh)														
42	COAL + GAS B.L. + OIL B.L.		3.34	3.47	3.39	3.30	3.55	3.42	3.08	3.06	3.04	3.02	#N/A	3.04	3.28
43	GAS-Generation		2.52	2.44	2.36	2.57	2.64	2.57	2.85	2.88	3.13	2.67	2.57	2.67	2.68
44	LANDFILL GAS		3.55	3.55	3.55	3.55	3.55	9.66	3.55	3.55	3.55	3.55	3.55	3.55	4.05
45	OIL - C.T.		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.72
46	TOTAL (¢/kWh)		2.89	2.85	2.56	2.71	2.99	3.03	2.86	2.89	3.01	2.69	2.55	2.71	2.83

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtus are not available due to contract specifications.

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: JANUARY 2020

(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	Crist 4	75		0%	100.0%	0.0%	0						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		0					0	0	0	146,591	N/A	N/A
4	Gas-S												
5	Oil-S												
6	Crist 5	75		46.7%	99.9%	56.0%	12,133						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		26,082					310,248	1,020	316,453	1,172,026	4.49	3.78
9	Gas-S												
10	Oil-S												
11	Crist 6	299		22.0%	97.4%	56.2%	10,973						
12	Coal		48,890					24,161	11,102	536,474	1,745,841	3.57	72.26
13	Gas-G		0					0	0	0	0	N/A	N/A
14	Gas-S												
15	Oil-S												
16	Crist 7	475		46.7%	98.9%	69.9%	10,381						
17	Coal		165,008					77,147	11,102	1,712,943	5,574,411	3.38	72.26
18	Gas-G		0					0	0	0	0	N/A	N/A
19	Gas-S												
20	Oil-S												
21	Smith 3	661	386,453	78.5%	99.3%	88.5%	6,874						
22	Gas-G							2,604,389	1,020	2,656,477	9,048,498	2.34	3.47
23	Smith A	40	80	0.3%	98.4%	0.1%	0						
24	Oil-G							0	0	0	0	0.00	N/A
25	Scherer 3	216	102,328	63.7%	98.8%	64.7%	10,626						
26	Coal							64,616	8,414	1,087,333	2,806,024	2.74	N/A
27	Oil												
28	Other Generation		5,712										
29	Gas										156,223	2.73	N/A
30	Perdido		2,097										
31	Landfill Gas										74,402	3.55	N/A
32	Blue Indigo	75	11,638	20.9%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	51,826	27.8%	98.3%	37.1%	11,880						
35	Coal							32,930	9,348	615,688	1,839,443	3.55	55.86
36	Oil-S												
37	Daniel 2	251	51,787	27.7%	97.4%	40.8%	11,374						
38	Coal							31,504	9,348	589,031	1,759,801	3.40	55.86
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							58,824	1,020	60,000	194,424	N/A	3.31
42	Ltr. Oil												
43	Oil							1,018	139,400	5,959	91,023	N/A	89.41
44	Total	2,418	851,901	47.4	95.6%	0.6	9,106			7,580,358	24,608,707	2.89	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **24,608,707** **2.89**

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: FEBRUARY 2020

(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	Crist 4	75		0%	100.0%	0.0%	0						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		0					0	0	0	137,134	N/A	N/A
4	Gas-S												
5	Oil-S												
6	Crist 5	75		27.0%	99.9%	56.0%	13,144						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		14,112					181,851	1,020	185,488	731,456	5.18	4.02
9	Gas-S												
10	Oil-S												
11	Crist 6	299		17.4%	97.6%	56.2%	10,973						
12	Coal		36,122					18,130	10,931	396,364	1,364,045	3.78	75.24
13	Gas-G		0					0	0	0	0	N/A	N/A
14	Gas-S												
15	Oil-S												
16	Crist 7	475		43.5%	98.9%	62.6%	10,490						
17	Coal		143,687					68,942	10,931	1,507,275	5,187,127	3.61	75.24
18	Gas-G		0					0	0	0	0	N/A	N/A
19	Gas-S												
20	Oil-S												
21	Smith 3	661	365,444	79.4%	99.3%	86.5%	6,808						
22	Gas-G							2,439,158	1,020	2,487,941	8,384,568	2.29	3.44
23	Smith A	40	0	0.0%	97.8%	0.0%	N/A						
24	Oil-G							0	0	0	0	N/A	N/A
25	Scherer 3	216	66,459	44.3%	98.7%	64.0%	10,489						
26	Coal							41,434	8,412	697,085	1,801,255	2.71	N/A
27	Oil												
28	Other Generation		5,344										
29	Gas										146,158	2.73	N/A
30	Perdido		1,962										
31	Landfill Gas										69,612	3.55	N/A
32	Blue Indigo	75	12,412	23.8%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	24,530	14.0%	98.3%	31.3%	12,044						
35	Coal							15,860	9,314	295,428	883,354	3.60	55.70
36	Oil-S												
37	Daniel 2	251	35,727	20.5%	97.4%	39.5%	10,556						
38	Coal							20,247	9,314	377,134	1,127,661	3.16	55.70
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							58,824	1,020	60,000	192,246	N/A	3.27
42	Ltr. Oil												
43	Oil							1,018	139,400	5,959	90,858	N/A	89.25
44	Total	2,418	705,799	41.9	95.6%	0.58	8,764			6,012,674	20,115,474	2.85	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **20,115,474** **2.85**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: MARCH 2020

(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	Crist 4	75		0%	80.6%	0.0%	0						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		0					0	0	0	146,591	N/A	N/A
4	Gas-S												
5	Oil-S												
6	Crist 5	75		0.0%	70.7%	0.0%	0						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		0					0	0	0	146,591	N/A	N/A
9	Gas-S												
10	Oil-S												
11	Crist 6	299		9.3%	18.7%	56.2%	10,973						
12	Coal		20,665					10,410	10,891	226,757	811,557	3.93	77.96
13	Gas-G		0					0	0	0	0	N/A	N/A
14	Gas-S												
15	Oil-S												
16	Crist 7	475		2.3%	19.4%	78.0%	10,326						
17	Coal		8,155					3,866	10,891	84,211	301,389	3.70	77.96
18	Gas-G		0					0	0	0	0	N/A	N/A
19	Gas-S												
20	Oil-S												
21	Smith 3	651	353,323	72.9%	80.1%	93.6%	6,864						
22	Gas-G							2,377,655	1,020	2,425,208	8,015,883	2.27	3.37
23	Smith A	36	72	0.3%	98.1%	0.1%	0						
24	Oil-G							0	0	0	0	0.00	N/A
25	Scherer 3	216	63,840	39.8%	79.6%	71.1%	10,393						
26	Coal							39,448	8,410	663,485	1,715,578	2.69	N/A
27	Oil												
28	Other Generation		5,712										
29	Gas										156,223	2.73	N/A
30	Perdido		2,097										
31	Landfill Gas										74,402	3.55	N/A
32	Blue Indigo	75	16,674	29.9%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	46,074	24.7%	72.8%	40.3%	11,858						
35	Coal							29,420	9,285	546,347	1,634,708	3.55	55.56
36	Oil-S												
37	Daniel 2	251	0	0.0%	78.6%	0.0%	N/A						
38	Coal							0	0	0	0	N/A	N/A
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							58,824	1,020	60,000	186,180	N/A	3.17
42	Ltr. Oil												
43	Oil							564	139,400	3,302	50,439	N/A	89.43
44	Total	2,404	516,612	28.9	57.0%	0.6	8,147			4,009,310	13,239,541	2.56	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **13,239,541** **2.56**

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: APRIL 2020

(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	Crist 4	75		0%	93.3%	0.0%	0						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		0					0	0	0	141,863	N/A	N/A
4	Gas-S												
5	Oil-S												
6	Crist 5	75		0.0%	86.3%	0.0%	0						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		0					0	0	0	141,863	N/A	N/A
9	Gas-S												
10	Oil-S												
11	Crist 6	299		0.0%	13.3%	0.0%	-						
12	Coal		0					0	0	0	0	N/A	N/A
13	Gas-G		0					0	0	0	0	N/A	N/A
14	Gas-S												
15	Oil-S												
16	Crist 7	475		8.4%	13.3%	63.9%	10,386						
17	Coal		28,830					13,765	10,876	299,431	1,110,049	3.85	80.64
18	Gas-G		0					0	0	0	0	N/A	N/A
19	Gas-S												
20	Oil-S												
21	Smith 3	651	353,908	75.5%	83.3%	94.0%	6,863						
22	Gas-G							2,381,245	1,020	2,428,870	8,791,283	2.48	3.69
23	Smith A	36	0	0.0%	98.5%	0.0%	N/A						
24	Oil-G							0	0	0	0	N/A	N/A
25	Scherer 3	216	80,251	51.7%	95.4%	61.9%	10,792						
26	Coal							51,495	8,409	866,064	2,241,265	2.79	N/A
27	Oil												
28	Other Generation		5,528										
29	Gas										151,191	2.74	N/A
30	Perdido		2,031										
31	Landfill Gas										72,060	3.55	N/A
32	Blue Indigo	75	18,060	33.4%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	38,031	21.0%	96.0%	34.4%	11,787						
35	Coal							24,258	9,240	448,276	1,338,274	3.52	55.17
36	Oil-S												
37	Daniel 2	251	17,857	9.9%	30.0%	51.9%	10,956						
38	Coal							10,587	9,240	195,646	584,077	3.27	55.17
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							29,412	1,020	30,000	87,084	N/A	2.96
42	Ltr. Oil												
43	Oil							967	139,400	5,659	86,130	N/A	89.07
44	Total	2,404	544,496	31.5	55.6%	0.5	8,237			4,273,946	14,745,139	2.71	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **14,745,139** **2.71**

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: MAY 2020

(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	Crist 4	75		50%	97.3%	56.9%	12,073						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		28,090					332,477	1,020	339,127	1,121,412	3.99	3.37
4	Gas-S												
5	Oil-S												
6	Crist 5	75		7.4%	99.9%	66.7%	11,244						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		4,150					45,747	1,020	46,662	280,721	6.76	6.14
9	Gas-S												
10	Oil-S												
11	Crist 6	299		11.8%	78.8%	56.2%	10,973						
12	Coal		26,221					13,089	10,991	287,719	1,047,780	4.00	80.05
13	Gas-G		0					0	0	0	0	N/A	N/A
14	Gas-S												
15	Oil-S												
16	Crist 7	475		52.2%	89.4%	67.4%	10,461						
17	Coal		184,636					87,865	10,991	1,931,474	7,033,809	3.81	80.05
18	Gas-G		0					0	0	0	0	N/A	N/A
19	Gas-S												
20	Oil-S												
21	Smith 3	651	354,470	73.2%	80.6%	93.4%	6,865						
22	Gas-G							2,385,724	1,020	2,433,438	8,807,829	2.48	3.69
23	Smith A	36	72	0.3%	98.4%	0.1%	0						
24	Oil-G							0	0	0	0	0.00	N/A
25	Scherer 3	216	97,692	60.9%	98.8%	62.1%	10,672						
26	Coal							62,014	8,406	1,042,570	2,701,149	2.76	N/A
27	Oil												
28	Other Generation		5,712										
29	Gas										156,223	2.73	N/A
30	Perdido		2,097										
31	Landfill Gas										74,402	3.55	N/A
32	Blue Indigo	75	20,573	36.9%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	6,872	3.7%	60.2%	38.0%	11,536						
35	Coal							4,306	9,206	79,274	236,267	3.44	54.87
36	Oil-S												
37	Daniel 2	251	27,811	14.9%	48.4%	40.9%	11,056						
38	Coal							16,700	9,206	307,474	916,387	3.30	54.87
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							58,824	1,020	60,000	172,470	N/A	2.93
42	Ltr. Oil												
43	Oil							1,018	139,400	5,959	90,604	N/A	89.00
44	Total	2,404	758,396	42.4	77.1%	0.6	8,950			6,533,697	22,639,053	2.99	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **22,639,053** **2.99**

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: JUNE 2020

(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	Crist 4	75		55%	97.2%	57.5%	12,006						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		29,519					347,451	1,020	354,400	1,172,777	3.97	3.38
4	Gas-S												
5	Oil-S												
6	Crist 5	75		5.5%	99.9%	66.4%	11,742						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		2,989					34,409	1,020	35,097	243,956	8.16	7.09
9	Gas-S												
10	Oil-S												
11	Crist 6	299		54.3%	97.1%	56.2%	10,973						
12	Coal		117,003					57,223	11,218	1,283,877	4,280,858	3.66	74.81
13	Gas-G		0					0	0	0	0	N/A	N/A
14	Gas-S												
15	Oil-S												
16	Crist 7	475		73.0%	98.9%	74.1%	10,597						
17	Coal		249,579					117,879	11,218	2,644,791	8,818,582	3.53	74.81
18	Gas-G		0					0	0	0	0	N/A	N/A
19	Gas-S												
20	Oil-S												
21	Smith 3	627	395,339	87.6%	99.3%	93.2%	6,874						
22	Gas-G							2,664,277	1,020	2,717,563	9,568,359	2.42	3.59
23	Smith A	32	0	0.0%	97.6%	0.0%	N/A						
24	Oil-G							0	0	0	0	N/A	N/A
25	Scherer 3	216	102,739	66.1%	98.8%	71.8%	10,612						
26	Coal							64,863	8,404	1,090,272	2,826,708	2.75	N/A
27	Oil												
28	Other Generation		5,528										
29	Gas										151,191	2.74	N/A
30	Perdido		2,031										
31	Landfill Gas										196,133	9.66	N/A
32	Blue Indigo	75	18,952	35.1%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	76,745	42.5%	98.2%	43.2%	11,264						
35	Coal							47,117	9,173	864,458	2,570,598	3.35	54.56
36	Oil-S												
37	Daniel 2	251	71,355	39.5%	96.7%	49.2%	11,040						
38	Coal							42,937	9,173	787,758	2,342,518	3.28	54.56
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							58,824	1,020	60,000	174,534	N/A	2.97
42	Ltr. Oil												
43	Oil							1,018	139,400	5,959	90,539	N/A	88.94
44	Total	2,376	1,071,779	62.7	95.3%	0.7	9,418			9,844,175	32,436,753	3.03	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **32,436,753** **3.03**

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: JULY 2020

(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	Crist 4	75		18%	97.3%	57.5%	12,019						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		9,913					116,811	1,020	119,147	497,634	5.02	4.26
4	Gas-S												
5	Oil-S												
6	Crist 5	75		48.6%	99.6%	63.6%	12,083						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		27,095					320,969	1,020	327,388	1,111,175	4.10	3.46
9	Gas-S												
10	Oil-S												
11	Crist 6	314		56.3%	97.4%	58.3%	10,930						
12	Coal		0					0	0	0	0	N/A	N/A
13	Gas-G		131,540					1,409,538	1,020	1,437,729	4,235,981	3.22	3.01
14	Gas-S												
15	Oil-S												
16	Crist 7	500		67.3%	98.9%	68.3%	10,637						
17	Coal		0					0	0	0	0	N/A	N/A
18	Gas-G		250,466					2,611,972	1,020	2,664,211	7,849,565	3.13	3.01
19	Gas-S												
20	Oil-S												
21	Smith 3	627	433,381	92.9%	99.3%	94.4%	6,994						
22	Gas-G							2,971,634	1,020	3,031,067	10,587,633	2.44	3.56
23	Smith A	32	0	0.0%	98.4%	0.0%	N/A						
24	Oil-G							846	139,400	4,951	77,888	N/A	92.10
25	Scherer 3	216	118,624	73.9%	98.8%	74.9%	10,587						
26	Coal							74,725	8,403	1,255,873	3,258,490	2.75	N/A
27	Oil												
28	Other Generation		5,712										
29	Gas										156,223	2.73	N/A
30	Perdido		2,097										
31	Landfill Gas										74,402	3.55	N/A
32	Blue Indigo	75	19,512	35.0%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	66,590	35.7%	98.3%	48.8%	11,054						
35	Coal							40,244	9,145	736,081	2,184,532	3.28	54.28
36	Oil-S												
37	Daniel 2	251	90,654	48.5%	96.6%	55.4%	11,039						
38	Coal							54,713	9,145	1,000,730	2,969,954	3.28	54.28
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							0	0	0	0	N/A	N/A
42	Ltr. Oil												
43	Oil							830	139,400	4,859	73,783	N/A	88.90
44	Total	2,416	1,155,584	64.3	95.4%	0.7	9,379			10,582,036	33,077,260	2.86	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **33,077,260** **2.86**

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: AUGUST 2020

(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	Crist 4	75		26%	97.3%	56.9%	12,073						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		14,777					174,899	1,020	178,397	674,361	4.56	3.86
4	Gas-S												
5	Oil-S												
6	Crist 5	75		52.5%	99.9%	62.6%	12,203						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		29,306					350,611	1,020	357,623	1,204,583	4.11	3.44
9	Gas-S												
10	Oil-S												
11	Crist 6	314		56.9%	97.4%	58.9%	10,925						
12	Coal		0					0	0	0	0	N/A	N/A
13	Gas-G		132,864					1,423,082	1,020	1,451,544	4,294,248	3.23	3.02
14	Gas-S												
15	Oil-S												
16	Crist 7	500		67.2%	99.2%	68.2%	10,639						
17	Coal		0					0	0	0	0	N/A	N/A
18	Gas-G		250,074					2,608,374	1,020	2,660,541	7,870,944	3.15	3.02
19	Gas-S												
20	Oil-S												
21	Smith 3	627	421,592	90.4%	99.3%	95.2%	7,022						
22	Gas-G							2,902,370	1,020	2,960,417	10,435,494	2.48	3.60
23	Smith A	32	64	0.3%	98.3%	0.1%	0						
24	Oil-G							0	0	0	0	0.00	N/A
25	Scherer 3	216	117,745	73.4%	98.8%	74.7%	10,482						
26	Coal							73,441	8,403	1,234,198	3,203,759	2.72	N/A
27	Oil												
28	Other Generation		5,712										
29	Gas										156,223	2.73	N/A
30	Perdido		2,097										
31	Landfill Gas										74,402	3.55	N/A
32	Blue Indigo	75	18,386	32.9%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	90,394	48.4%	98.3%	49.3%	11,037						
35	Coal							54,692	9,121	997,674	2,955,756	3.27	54.04
36	Oil-S												
37	Daniel 2	251	95,570	51.2%	96.9%	55.5%	10,857						
38	Coal							56,881	9,121	1,037,605	3,074,059	3.22	54.04
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							0	0	0	0	N/A	N/A
42	Ltr. Oil												
43	Oil							830	139,400	4,859	73,747	N/A	88.85
44	Total	2,416	1,178,581	65.6	95.5%	0.7	9,444			10,882,858	34,017,576	2.89	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **34,017,576** **2.89**

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: SEPTEMBER 2020

(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	Crist 4	75		54%	96.8%	57.2%	12,046						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		29,292					345,931	1,020	352,850	1,180,723	4.03	3.41
4	Gas-S												
5	Oil-S												
6	Crist 5	75		53.2%	99.9%	61.4%	12,378						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		28,720					348,527	1,020	355,498	1,188,520	4.14	3.41
9	Gas-S												
10	Oil-S												
11	Crist 6	314		7.1%	58.8%	53.5%	10,973						
12	Coal		0					0	0	0	0	N/A	N/A
13	Gas-G		16,130					173,525	1,020	176,995	521,109	3.23	3.00
14	Gas-S												
15	Oil-S												
16	Crist 7	500		6.5%	59.0%	48.7%	11,195						
17	Coal		0					0	0	0	0	N/A	N/A
18	Gas-G		23,372					256,514	1,020	261,644	770,332	3.30	3.00
19	Gas-S												
20	Oil-S												
21	Smith 3	627	235,913	52.2%	56.3%	94.3%	6,951						
22	Gas-G							1,607,677	1,020	1,639,831	6,784,238	2.88	4.22
23	Smith A	32	128	0.6%	98.5%	0.1%	0						
24	Oil-G							0	0	0	0	0.00	N/A
25	Scherer 3	216	109,265	70.3%	98.8%	71.3%	10,659						
26	Coal							69,307	8,402	1,164,653	3,023,748	2.77	N/A
27	Oil												
28	Other Generation		5,528										
29	Gas										151,191	2.74	N/A
30	Perdido		2,031										
31	Landfill Gas										72,060	3.55	N/A
32	Blue Indigo	75	16,506	30.6%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	23,325	12.9%	80.0%	50.5%	10,999						
35	Coal							14,099	9,098	256,552	758,869	3.25	53.82
36	Oil-S												
37	Daniel 2	251	87,339	48.3%	97.5%	50.6%	10,994						
38	Coal							52,767	9,098	960,205	2,840,248	3.25	53.83
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							0	0	0	0	N/A	N/A
42	Ltr. Oil												
43	Oil							830	139,400	4,859	73,721	N/A	88.82
44	Total	2,416	577,549	33.2	69.1%	0.6	9,346			5,173,087	17,364,759	3.01	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **17,364,759** **3.01**

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: OCTOBER 2020

(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	Crist 4	75		7%	96.1%	56.0%	12,170						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		4,032					48,107	1,020	49,069	292,253	7.25	6.08
4	Gas-S												
5	Oil-S												
6	Crist 5	75		0.0%	99.9%	0.0%	0						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		0					0	0	0	146,591	N/A	N/A
9	Gas-S												
10	Oil-S												
11	Crist 6	314		45.0%	91.3%	53.5%	10,973						
12	Coal		0					0	0	0	0	N/A	N/A
13	Gas-G		105,022					1,129,814	1,020	1,152,410	3,420,929	3.26	3.03
14	Gas-S												
15	Oil-S												
16	Crist 7	500		0.0%	70.8%	0.0%	-						
17	Coal		0					0	0	0	0	N/A	N/A
18	Gas-G		0					0	0	0	0	N/A	N/A
19	Gas-S												
20	Oil-S												
21	Smith 3	651	404,428	83.5%	89.8%	93.8%	6,763						
22	Gas-G							2,681,515	1,020	2,735,145	9,858,025	2.44	3.68
23	Smith A	36	0	0.0%	98.4%	0.0%	N/A						
24	Oil-G							0	0	0	0	N/A	N/A
25	Scherer 3	216	87,675	54.6%	98.7%	62.3%	10,668						
26	Coal							55,655	8,403	935,319	2,428,212	2.77	N/A
27	Oil												
28	Other Generation		5,712										
29	Gas										156,223	2.73	N/A
30	Perdido		2,097										
31	Landfill Gas										74,402	3.55	N/A
32	Blue Indigo	75	15,970	28.6%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	0	0.0%	0.0%	0.0%	N/A						
35	Coal							0	0	0	0	N/A	N/A
36	Oil-S												
37	Daniel 2	251	65,569	35.1%	97.4%	45.4%	11,177						
38	Coal							40,554	9,036	732,867	2,147,251	3.27	52.95
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							0	0	0	0	N/A	N/A
42	Ltr. Oil												
43	Oil							521	139,400	3,052	46,411	N/A	89.08
44	Total	2,444	690,505	38.0	76.3%	0.4	8,411			5,607,862	18,570,297	2.69	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **18,570,297** **2.69**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: NOVEMBER 2020

(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	Crist 4	75		0%	100.0%	0.0%	0						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		0					0	0	0	141,863	N/A	N/A
4	Gas-S												
5	Oil-S												
6	Crist 5	75		0.0%	99.9%	0.0%	0						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		0					0	0	0	141,863	N/A	N/A
9	Gas-S												
10	Oil-S												
11	Crist 6	314		14.2%	97.6%	53.5%	10,973						
12	Coal		0					0	0	0	0	N/A	N/A
13	Gas-G		32,092					345,241	1,020	352,146	1,067,425	3.33	3.09
14	Gas-S												
15	Oil-S												
16	Crist 7	500		33.4%	100.0%	45.3%	10,653						
17	Coal		0					0	0	0	0	N/A	N/A
18	Gas-G		120,190					1,255,280	1,020	1,280,386	3,881,106	3.23	3.09
19	Gas-S												
20	Oil-S												
21	Smith 3	651	388,629	82.9%	92.8%	92.0%	7,043						
22	Gas-G							2,683,448	1,020	2,737,117	8,666,886	2.23	3.23
23	Smith A	36	0	0.0%	98.3%	0.0%	N/A						
24	Oil-G							0	0	0	0	N/A	N/A
25	Scherer 3	216	58,809	37.9%	98.6%	49.2%	10,820						
26	Coal							37,861	8,403	636,311	1,651,726	2.81	N/A
27	Oil												
28	Other Generation		5,528										
29	Gas										151,191	2.74	N/A
30	Perdido		2,031										
31	Landfill Gas										72,060	3.55	N/A
32	Blue Indigo	75	12,516	23.2%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	0	0.0%	0.0%	0.0%	N/A						
35	Coal							0	0	0	0	N/A	N/A
36	Oil-S												
37	Daniel 2	251	0	0.0%	81.3%	0.0%	N/A						
38	Coal							0	0	0	0	N/A	N/A
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							0	0	0	0	N/A	N/A
42	Ltr. Oil												
43	Oil							67	139,400	395	6,281	N/A	93.75
44	Total	2,444	619,795	35.2	82.4%	0.4	8,348			5,006,355	15,780,401	2.55	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **15,780,401** **2.55**

Schedule E-4

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: DECEMBER 2020

(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	Crist 4	75		0%	100.0%	0.0%	0						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		0					0	0	0	146,591	N/A	N/A
4	Gas-S												
5	Oil-S												
6	Crist 5	75		0.0%	99.9%	0.0%	0						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		0					0	0	0	146,591	N/A	N/A
9	Gas-S												
10	Oil-S												
11	Crist 6	314		43.2%	97.4%	53.5%	10,973						
12	Coal		0					0	0	0	0	N/A	N/A
13	Gas-G		100,981					1,086,336	1,020	1,108,063	3,541,369	3.51	3.26
14	Gas-S												
15	Oil-S												
16	Crist 7	500		8.7%	95.7%	45.2%	11,345						
17	Coal		0					0	0	0	0	N/A	N/A
18	Gas-G		32,318					359,459	1,020	366,648	1,171,807	3.63	3.26
19	Gas-S												
20	Oil-S												
21	Smith 3	661	398,370	81.0%	99.3%	89.0%	6,872						
22	Gas-G							2,683,919	1,020	2,737,597	9,164,861	2.30	3.41
23	Smith A	40	0	0.0%	98.1%	0.0%	N/A						
24	Oil-G							0	0	0	0	N/A	N/A
25	Scherer 3	216	95,375	59.4%	98.7%	65.0%	10,621						
26	Coal							60,280	8,402	1,012,981	2,629,976	2.76	N/A
27	Oil												
28	Other Generation		5,712										
29	Gas										156,223	2.73	N/A
30	Perdido		2,097										
31	Landfill Gas										74,402	3.55	N/A
32	Blue Indigo	75	9,900	17.7%									
33	Solar										0	0.00	N/A
34	Daniel 1	251	0	0.0%	64.5%	0.0%	N/A						
35	Coal							0	0	0	0	N/A	N/A
36	Oil-S												
37	Daniel 2	251	58,594	31.4%	97.6%	39.2%	11,453						
38	Coal							36,686	9,146	671,079	2,000,980	3.41	54.54
39	Oil-S							0	0	0	0		
40	Gas,BL												
41	Gas							0	0	0	0	N/A	N/A
42	Ltr. Oil												
43	Oil							521	139,400	3,052	46,406	N/A	89.07
44	Total	2,458	703,347	38.5	91.5%	0.5	8,604			5,899,420	19,079,206	2.71	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **19,079,206** **2.71**

GULF POWER COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: JANUARY - DECEMBER 2020

(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	Crist 4	75		17.6%	96.3%	57.2%	12,048						
2	Coal		0					0	0	0	0	N/A	N/A
3	Gas-G		115,623					1,365,676	510	1,392,990	5,799,793	5.02	4.25
4	Gas-S												
5	Oil-S												
6	Crist 5	75		20.1%	96.3%	60.6%	12,262						
7	Coal		0					0	0	0	0	N/A	N/A
8	Gas-G		132,454					1,592,362	595	1,624,209	6,655,936	5.03	4.18
9	Gas-S												
10	Oil-S												
11	Crist 6	307		28.5%	78.6%	56.5%	10,957						
12	Coal		248,901					123,013	4,594	2,731,191	9,250,081	3.72	75.20
13	Gas-G		518,629					5,567,536	510	5,678,887	17,081,061	3.29	3.07
14	Gas-S												
15	Oil-S												
16	Crist 7	488		34.0%	78.5%	64.7%	10,584						
17	Coal		779,895					369,464	5,501	8,180,125	28,025,367	3.59	75.85
18	Gas-G		676,420					7,091,599	425	7,233,430	21,543,754	3.18	3.04
19	Gas-S												
20	Oil-S												
21	Smith 3	646	4,491,250	79.2%	89.9%	92.2%	6,900	0		0	0		
22	Gas-G							30,383,011	1,020	30,990,671	108,113,557	2.41	3.56
23	Smith A	36	416	0.1%	98.2%	0.1%	11,901				0		
24	Oil-G							846	11,617	4,951	77,888	18.72	92.10
25	Scherer 3	216	1,100,802	58.1%	96.8%	66.4%	10,616						
26	Coal		0					695,139	8,406	11,686,144	30,287,890	2.75	43.57
27	Oil												
28	Other Generation		67,440										
29	Gas									0	1,844,483	2.73	N/A
30	Perdido		24,765										
31	Landfill Gas									0	1,002,739	4.05	N/A
32	Blue Indigo	75	191,099	29.0%									
33	Solar									0	0	0.00	N/A
34	Daniel 1	251	424,387	19.2%	72.0%	42.2%	11,404						
35	Coal		0					262,926	6,911	4,839,778	14,401,801	3.39	54.78
36	Oil-S												
37	Daniel 2	251	602,263	27.3%	84.7%	47.5%	11,058			0			
38	Coal		0					363,576	7,652	6,659,529	19,762,936	3.28	54.36
39	Oil-S												
40	Gas,BL												
41	Gas							323,532	510	330,000	1,006,938	N/A	3.11
42	Ltr. Oil												
43	Oil							9,202	139,400	53,873	819,942	N/A	89.10
44	Total	2,418	9,374,344	44.1	82.1%	63.7%	8,955			81,405,778	265,674,166	2.83	

Notes:
(1) Smith A uses lighter oil
(2) Represents Gulf's 25% ownership
(3) Represents Gulf's 50% ownership

Recoverable Fuel **265,674,166** **2.83**

GULF POWER COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Description		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
	LIGHT OIL														
1	*PURCHASES :*														
2	UNITS	(BBL)	1,021	1,021	567	970	1,021	1,021	833	833	833	518	71	524	9,233
3	UNIT COST	($/BBL)	76.61	76.61	67.22	78.44	76.61	76.61	84.42	84.42	84.42	82.59	42.00	82.10	78.72
4	AMOUNT	($)	78,212	78,212	38,126	76,060	78,212	78,212	70,321	70,321	70,321	42,793	2,967	43,054	726,811
5	*BURNED :*														
6	UNITS	(BBL)	1,018	1,018	564	967	1,018	1,018	830	830	830	521	67	521	9,202
7	UNIT COST	($/BBL)	89.41	89.25	89.43	89.07	89.00	88.94	88.90	88.85	88.82	89.08	93.75	89.07	89.10
8	AMOUNT	($)	91,023	90,858	50,439	86,130	90,604	90,539	73,783	73,747	73,721	46,411	6,281	46,406	819,942
9	*ENDING INVENTORY :*														
10	UNITS	(BBL)	6,860	6,863	6,866	6,869	6,871	6,874	6,877	6,880	6,883	6,881	6,884	6,888	
11	UNIT COST	($/BBL)	85.61	83.74	81.90	80.41	78.57	76.74	76.21	75.67	75.15	74.65	74.13	73.61	
12	AMOUNT	($)	587,304	574,658	562,345	552,275	539,883	527,556	524,094	520,668	517,268	513,650	510,336	506,984	
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	
	COAL(EXCLUDING SCHERER)														
14	*PURCHASES :*														
15	UNITS	(TONS)	173,000	126,000	66,000	70,000	115,552	245,137	70,000	70,000	70,000	64,000	52,000	44,000	1,165,689
16	UNIT COST	($/TON)	72.23	72.60	69.93	64.34	64.83	65.44	61.38	61.38	61.38	58.72	69.38	72.96	66.71
17	AMOUNT	($)	12,495,559	9,147,346	4,615,546	4,503,563	7,490,931	16,042,464	4,296,511	4,296,511	4,296,511	3,757,840	3,607,617	3,210,429	77,760,828
18	*BURNED :*														
19	UNITS	(TONS)	165,742	123,179	43,696	48,610	121,960	265,156	94,957	111,573	66,866	40,554	0	36,686	1,118,979
20	UNIT COST	($/TON)	65.88	69.51	62.88	62.38	75.72	67.93	54.28	54.04	53.83	52.95	0.00	54.54	63.84
21	AMOUNT	($)	10,919,496	8,562,187	2,747,654	3,032,400	9,234,243	18,012,556	5,154,486	6,029,815	3,599,117	2,147,251	0	2,000,980	71,440,185
22	*ENDING INVENTORY :*														
23	UNITS	(TONS)	526,469	529,290	551,594	572,984	566,576	546,557	521,600	480,027	483,161	506,607	558,607	565,921	
24	UNIT COST	($/TON)	64.42	65.19	65.94	66.04	63.71	62.44	63.78	65.70	66.71	66.81	67.05	68.32	
25	AMOUNT	($)	33,917,035	34,502,194	36,370,086	37,841,249	36,097,937	34,127,845	33,269,870	31,536,566	32,233,960	33,844,549	37,452,166	38,661,615	
26	DAYS SUPPLY:		33	33	35	36	35	34	33	30	30	32	35	35	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBtus are not available due to contract specifications.

GULF POWER COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
Line No.		Description	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
	COAL at Plant Scherer														
27		*PURCHASES :*													
28		UNITS (MMBTU	963,210	807,013	653,142	859,455	1,050,351	1,001,475	1,275,799	1,167,259	1,103,991	885,335	804,587	935,418	11,507,035
29		UNIT COST ($/MMBT	2.60	2.59	2.59	2.59	2.60	2.60	2.60	2.60	2.60	2.60	2.59	2.60	2.60
30		AMOUNT ($)	2,501,113	2,094,016	1,693,533	2,229,991	2,729,322	2,601,427	3,315,356	3,033,314	2,867,441	2,298,091	2,087,601	2,430,017	29,881,222
31		*BURNED :*													
32		UNITS (MMBTU	1,087,333	1,087,333	1,087,333	1,087,333	1,087,333	1,087,333	1,087,333	1,087,333	1,087,333	1,087,333	1,087,333	1,087,333	13,047,996
33		UNIT COST ($/MMBT	2.58	1.66	1.58	2.06	2.48	2.60	3.00	2.95	2.78	2.23	1.52	2.42	2.32
34		AMOUNT ($)	2,806,024	1,801,255	1,715,578	2,241,265	2,701,149	2,826,708	3,258,490	3,203,759	3,023,748	2,428,212	1,651,726	2,629,976	30,287,890
35		*ENDING INVENTORY :*													
36		UNITS (MMBTU	2,562,544	2,282,224	1,848,033	1,620,155	1,583,173	1,497,315	1,685,781	1,765,707	1,782,365	1,580,367	1,297,621	1,145,706	
37		UNIT COST ($/MMBT	2.61	3.06	3.77	4.29	4.41	4.51	4.04	3.76	3.64	4.02	5.23	5.75	
38		AMOUNT ($)	6,693,785	6,986,546	6,964,501	6,953,227	6,981,400	6,756,119	6,812,985	6,642,540	6,486,233	6,356,112	6,791,987	6,592,028	
39	DAYS SUPPLY:		48	43	34	30	30	28	31	33	33	29	24	21	
	GAS (1)														
40		*BURNED :*													
41		UNITS (MMBtu)	3,032,930	2,733,429	2,485,208	2,458,870	2,879,227	3,167,060	7,579,542	7,608,522	2,786,818	3,936,624	4,369,649	4,212,308	47,250,187
42		UNIT COST ($/MMBt	3.48	3.46	3.42	3.73	3.61	3.52	3.20	3.22	3.75	3.48	3.18	3.36	3.39
43		AMOUNT ($)	10,561,539	9,445,404	8,495,245	9,162,093	10,382,432	11,159,626	24,281,988	24,479,630	10,444,922	13,717,798	13,899,143	14,171,219	160,201,039
	OTHER - C.T. OIL														
44		*PURCHASES :*													
45		UNITS (BBL)	0	0	0	0	0	0	846	0	0	0	0	0	846
46		UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	88.11	0.00	0.00	0.00	0.00	0.00	88.08
47		AMOUNT ($)	0	0	0	0	0	0	74,518	0	0	0	0	0	74,518
48		*BURNED :*													
49		UNITS (BBL)	0.00	0.00	0.00	0.00	0.00	0.00	845.69	0.00	0	0.00	0.00	0.00	846
50		UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	92.10	0.00	0.00	0.00	0.00	0.00	92.07
51		AMOUNT ($)	0	0	0	0	0	0	77,888	0	0	0	0	0	77,888
52		*ENDING INVENTORY :*													
53		UNITS (BBL)	6,376	6,376	6,376	6,376	6,376	6,376	6,376	6,376	6,376	6,376	6,376	6,376	
54		UNIT COST ($/BBL)	92.69	92.69	92.69	92.69	92.69	92.69	92.16	92.16	92.16	92.16	92.16	92.16	
55		AMOUNT ($)	590,980	590,980	590,980	590,980	590,980	590,980	587,610	587,610	587,610	587,610	587,610	587,610	
56	HOURS SUPPLY:		72	72	72	72	72	72	72	72	72	72	72	72	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBtus are not available due to contract specifications.

Schedule E-6
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GULF POWER COMPANY
POWER SOLD

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)
					¢ / kWh			
Line No.	Month	Type	Total KWH Sold	KWH From Own Generation	Fuel Costs	Total Costs	Total $ for Fuel Adjustment	Total Cost ($)
	JANUARY							
1		Southern Co. Interchange	545,135,000	545,135,000	2.43	2.81	13,220,914	15,332,424
2		Economy Sales	8,724,000	8,724,000	2.48	2.84	216,423	247,570
3		Gain on Economy Sales	0	0	0.00	0.00	23,000	23,000
4		TOTAL ESTIMATED SALES	553,859,000	553,859,000	2.43	2.82	13,460,337	15,602,994
	FEBRUARY							
5		Southern Co. Interchange	417,195,000	417,195,000	2.30	2.62	9,594,623	10,923,138
6		Economy Sales	13,169,000	13,169,000	2.41	2.69	316,752	353,872
7		Gain on Economy Sales	0	0	0.00	0.00	21,000	21,000
8		TOTAL ESTIMATED SALES	430,364,000	430,364,000	2.31	2.63	9,932,375	11,298,010
	MARCH							
9		Southern Co. Interchange	439,905,000	439,905,000	2.33	2.69	10,242,137	11,836,196
10		Economy Sales	10,921,000	10,921,000	2.55	2.94	278,367	320,738
11		Gain on Economy Sales	0	0	0.00	0.00	14,000	14,000
12		TOTAL ESTIMATED SALES	450,826,000	450,826,000	2.34	2.70	10,534,504	12,170,934
	APRIL							
13		Southern Co. Interchange	217,917,000	217,917,000	2.28	2.60	4,967,375	5,670,760
14		Economy Sales	8,184,000	8,184,000	2.47	2.78	202,116	227,645
15		Gain on Economy Sales	0	0	0.00	0.00	8,000	8,000
16		TOTAL ESTIMATED SALES	226,101,000	226,101,000	2.29	2.61	5,177,491	5,906,405
	MAY							
17		Southern Co. Interchange	454,023,000	454,023,000	2.26	2.59	10,251,501	11,746,474
18		Economy Sales	6,751,000	6,751,000	2.40	2.72	162,146	183,898
19		Gain on Economy Sales	0	0	0.00	0.00	14,000	14,000
20		TOTAL ESTIMATED SALES	460,774,000	460,774,000	2.26	2.59	10,427,647	11,944,372
	JUNE							
21		Southern Co. Interchange	585,898,000	585,898,000	2.44	2.83	14,310,710	16,562,390
22		Economy Sales	7,829,000	7,829,000	2.72	3.02	213,177	236,140
23		Gain on Economy Sales	0	0	0.00	0.00	24,000	24,000
24		TOTAL ESTIMATED SALES	593,727,000	593,727,000	2.45	2.83	14,547,887	16,822,530

GULF POWER COMPANY
POWER SOLD

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)
Line No.	Month	Type	Total KWH Sold	KWH From Own Generation	¢ / kWh Costs	¢ / kWh Costs	Total $ for Fuel Adjustment	Total Cost ($)
	JULY							
1		Southern Co. Interchange	593,112,000	593,112,000	2.62	2.96	15,511,736	17,585,460
2		Economy Sales	8,426,000	8,426,000	2.93	3.23	246,617	271,992
3		Gain on Economy Sales	0	0	0.00	0.00	29,000	29,000
4		TOTAL ESTIMATED SALES	601,538,000	601,538,000	2.62	2.97	15,787,353	17,886,452
	AUGUST							
5		Southern Co. Interchange	626,694,000	626,694,000	2.65	3.00	16,585,532	18,824,789
6		Economy Sales	10,418,000	10,418,000	2.95	3.26	307,312	339,314
7		Gain on Economy Sales	0	0	0.00	0.00	30,000	30,000
8		TOTAL ESTIMATED SALES	637,112,000	637,112,000	2.66	3.01	16,922,844	19,194,103
	SEPTEMBER							
9		Southern Co. Interchange	223,468,000	223,468,000	2.35	2.70	5,255,292	6,042,556
10		Economy Sales	7,998,000	7,998,000	2.81	3.11	224,513	248,539
11		Gain on Economy Sales	0	0	0.00	0.00	20,000	20,000
12		TOTAL ESTIMATED SALES	231,466,000	231,466,000	2.38	2.73	5,499,805	6,311,095
	OCTOBER							
13		Southern Co. Interchange	234,349,000	234,349,000	2.10	2.46	4,917,683	5,767,293
14		Economy Sales	9,400,000	9,400,000	2.36	2.72	222,099	255,752
15		Gain on Economy Sales	0	0	0.00	0.00	10,000	10,000
16		TOTAL ESTIMATED SALES	243,749,000	243,749,000	2.11	2.48	5,149,782	6,033,045
	NOVEMBER							
17		Southern Co. Interchange	497,322,000	497,322,000	2.11	2.39	10,485,194	11,890,038
18		Economy Sales	7,339,000	7,339,000	2.35	2.62	172,181	192,196
19		Gain on Economy Sales	0	0	0.00	0.00	12,000	12,000
20		TOTAL ESTIMATED SALES	504,661,000	504,661,000	2.11	2.40	10,669,375	12,094,234
	DECEMBER							
21		Southern Co. Interchange	462,875,000	462,875,000	2.34	2.71	10,843,879	12,550,232
22		Economy Sales	10,328,000	10,328,000	2.47	2.82	255,345	291,715
23		Gain on Economy Sales	0	0	0.00	0.00	18,000	18,000
24		TOTAL ESTIMATED SALES	473,203,000	473,203,000	2.35	2.72	11,117,224	12,859,947
	TOTAL							
25		Southern Co. Interchange	5,297,893,000	5,297,893,000	2.38	2.73	126,186,576	144,731,750
26		Economy Sales	109,487,000	109,487,000	2.57	2.89	2,817,048	3,169,371
27		Gain on Economy Sales	0	0	0.00	0.00	223,000	223,000
28		TOTAL ESTIMATED SALES	5,407,380,000	5,407,380,000	2.39	2.74	129,226,624	148,124,121

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

PROPOSED FOR THE PERIOD: JANUARY 2020 - 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	¢ / kWh Fuel Cost	¢ / kWh 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

PROPOSED FOR THE PERIOD: JANUARY 2020 - 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	¢ / kWh Fuel Cost	¢ / kWh Total Cost	Total $ for Fuel Adj
1	JANUARY		COG-1	0			None	0	0.00	0
2	FEBRUARY		COG-1	0			None	0	0.00	0
3	MARCH		COG-1	0			None	0	0.00	0
4	APRIL		COG-1	0			None	0	0.00	0
5	MAY		COG-1	0			None	0	0.00	0
6	JUNE		COG-1	0			None	0	0.00	0
7	JULY		COG-1	0			None	0	0.00	0
8	AUGUST		COG-1	0			None	0	0.00	0
9	SEPTEMBER		COG-1	0			None	0	0.00	0
10	OCTOBER		COG-1	0			None	0	0.00	0
11	NOVEMBER		COG-1	0			None	0	0.00	0
12	DECEMBER		COG-1	0			None	0	0.00	0
13	TOTAL			0			0	0.00	0.00	0

GULF POWER COMPANY
ECONOMY ENERGY PURCHASES

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(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	7,738,000	2.05	158,822
2		Economy Energy	3,242,000	2.89	93,810
3		Other Purchases	619,432,000	2.89	17,895,000
4		TOTAL ESTIMATED PURCHASES	630,412,000	2.88	18,147,632
	FEBRUARY				
5		Southern Co. Interchange	9,034,000	1.96	177,065
6		Economy Energy	3,769,000	2.83	106,513
7		Other Purchases	525,165,000	2.89	15,180,000
8		TOTAL ESTIMATED PURCHASES	537,968,000	2.87	15,463,578
	MARCH				
9		Southern Co. Interchange	9,398,000	3.19	300,190
10		Economy Energy	4,983,000	3.08	153,623
11		Other Purchases	695,230,000	2.89	20,122,000
12		TOTAL ESTIMATED PURCHASES	709,611,000	2.90	20,575,813
	APRIL				
13		Southern Co. Interchange	54,318,000	2.71	1,472,877
14		Economy Energy	3,754,000	2.70	101,446
15		Other Purchases	419,682,000	3.28	13,769,000
16		TOTAL ESTIMATED PURCHASES	477,754,000	3.21	15,343,323
	MAY				
17		Southern Co. Interchange	11,163,000	2.80	313,027
18		Economy Energy	3,369,000	2.69	90,731
19		Other Purchases	675,418,000	2.70	18,262,000
20		TOTAL ESTIMATED PURCHASES	689,950,000	2.71	18,665,758
	JUNE				
21		Southern Co. Interchange	1,602,000	2.38	38,172
22		Economy Energy	4,863,000	3.02	147,036
23		Other Purchases	667,652,000	2.81	18,736,000
24		TOTAL ESTIMATED PURCHASES	674,117,000	2.81	18,921,208

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GULF POWER COMPANY
ECONOMY ENERGY PURCHASES

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1) Line No.	(2) Month	(3) Type & Schedule	(4) Total KWH Purchased	(5) Transaction Cost ¢ / kWh	(6) Total $ for Fuel Adj.
	JULY				
1		Southern Co. Interchange	51,000	2.28	1,165
2		Economy Energy	5,087,000	3.31	168,226
3		Other Purchases	689,062,000	2.73	18,816,000
4		TOTAL ESTIMATED PURCHASES	694,200,000	2.73	18,985,391
	AUGUST				
5		Southern Co. Interchange	590,000	2.65	15,660
6		Economy Energy	5,117,000	3.20	163,721
7		Other Purchases	690,073,000	2.75	18,994,000
8		TOTAL ESTIMATED PURCHASES	695,780,000	2.76	19,173,381
	SEPTEMBER				
9		Southern Co. Interchange	31,914,000	3.26	1,040,931
10		Economy Energy	5,084,000	3.22	163,854
11		Other Purchases	674,181,000	2.76	18,640,000
12		TOTAL ESTIMATED PURCHASES	711,179,000	2.79	19,844,785
	OCTOBER				
13		Southern Co. Interchange	32,540,000	2.92	950,405
14		Economy Energy	3,928,000	2.56	100,552
15		Other Purchases	405,838,000	3.20	12,969,000
16		TOTAL ESTIMATED PURCHASES	442,306,000	3.17	14,019,957
	NOVEMBER				
17		Southern Co. Interchange	269,000	2.78	7,481
18		Economy Energy	4,485,000	2.68	120,217
19		Other Purchases	652,986,000	2.88	18,787,000
20		TOTAL ESTIMATED PURCHASES	657,740,000	2.88	18,914,698
	DECEMBER				
21		Southern Co. Interchange	1,384,000	2.53	34,953
22		Economy Energy	4,414,000	3.01	132,928
23		Other Purchases	634,180,000	2.86	18,146,000
24		TOTAL ESTIMATED PURCHASES	639,978,000	2.86	18,313,881
	TOTAL FOR PERIOD				
25		Southern Co. Interchange	160,001,000	2.82	4,510,748
26		Economy Energy	52,095,000	2.96	1,542,657
27		Other Purchases	7,348,899,000	2.86	210,316,000
28		TOTAL ESTIMATED PURCHASES	7,560,995,000	2.86	216,369,405

SCHEDULE E-10

GULF POWER COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 kWh

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Bill Component	Current Approved 2019 ($/1,000 kWh)	Proposed 2020 ($/1,000 kWh)	Difference from Current ($)	Difference from Current (%)
1	Base Rate	$ 68.06	$ 68.06	$ -	0.0%
2	Fuel Cost Recovery	30.47	32.62	2.15	7.1%
3	Capacity Cost Recovery	7.76	8.78	1.02	13.1%
4	Energy Conservation Cost Recovery	1.25	0.60	(0.65)	-52.0%
5	Environmental Cost Recovery	18.10	18.97	0.87	4.8%
6	Storm	8.00	8.00	-	0.0%
7	Subtotal	$ 133.64	$ 137.03	$ 3.39	2.5%
8	Gross Receipts Tax	3.43	3.52	0.09	2.6%
9	Total	$ 137.07	$ 140.55	$ 3.48	2.5%

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SCHEDULE E-11

GULF POWER COMPANY
ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2022

Year: 2020	
Month	Total ¢ / kWh
JANUARY	2.536
FEBRUARY	2.536
MARCH	2.536
APRIL	2.768
MAY	2.768
JUNE	2.768
JULY	2.768
AUGUST	2.768
SEPTEMBER	2.768
OCTOBER	2.768
NOVEMBER	2.536
DECEMBER	2.536

Schedule H-1
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GULF POWER COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(2) (3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
						% Change		
LINE	LINE DESCRIPTION	2017	2018	2019	2020	2018	2019	2019 to 2020
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	LIGHTER OIL (B.L.)	735,886	882,162	1,001,330	819,942	19.88	13.51	(18.11)
2	COAL	140,114,416	113,947,937	125,761,821	71,440,185	(18.68)	10.37	(43.19)
2a	COAL at Scherer	17,121,552	34,571,593	23,282,891	30,287,890	101.92	(32.65)	30.09
2b	Flint Credit	0	(8,297,183)	(5,587,895)	0	(100.00)	(32.65)	(100.00)
3	GAS-Generation	109,160,533	113,385,721	105,577,111	159,194,101	3.87	(6.89)	50.78
4	GAS (B.L.)	4,156,086	4,195,667	462,391	1,006,938	0.95	(88.98)	117.77
5	LANDFILL GAS	774,446	835,811	740,970	1,002,739	7.92	(11.35)	35.33
6	OTHER - C.T.	0	155,064	21,960	77,888	100.00	(85.84)	254.68
7	OTHER GENERATION	2,514,497	2,902,925	2,390,125	1,844,483	15.45	(17.66)	(22.83)
8	TOTAL ($)	274,577,416	262,579,697	253,650,704	265,674,166	(4.37)	(3.40)	4.74
	SYSTEM NET GENERATION (MWh)							
9	COAL	4,450,261	3,584,903	3,792,741	2,055,446	(19.45)	5.80	(45.81)
9a	COAL at Scherer	798,738	1,353,538	873,821	1,100,802	69.46	(35.44)	25.98
9b	Flint Credit	0	(324,848)	(209,718)	0	(100.00)	(35.44)	(100.00)
10	GAS	3,997,684	4,031,809	4,197,515	5,934,376	0.85	4.11	41.38
11	LANDFILL GAS	24,719	24,699	24,699	24,765	(0.08)	0.00	0.27
12	OTHER - C.T.	0	672	96	416	100.00	(85.71)	333.33
13	OTHER GENERATION	81,428	81,360	81,352	67,440	(0.08)	(0.01)	(17.10)
14	Solar	0	0	0	191,099	0.00	0.00	100.00
15	TOTAL (MWH)	9,352,830	8,752,133	8,760,506	9,374,344	(6.42)	0.10	7.01
	UNITS OF FUEL BURNED							
16	LIGHTER OIL (BBL)	10,947	12,482	10,297	9,202	14.02	(17.50)	(10.63)
17	COAL excl. Scherer (TON)	2,081,172	1,849,633	1,903,268	1,118,979	(11.13)	2.90	(41.21)
18	GAS (MCF)	27,121,109	27,650,559	28,470,077	46,323,716	1.95	2.96	62.71
19	OTHER - C.T. (BBL)	0	1,605	231	846	100.00	(85.61)	266.23
	BTUS BURNED (MMBtu)							
20	COAL + GAS B.L. + OIL B.L.	53,815,132	51,302,066	48,882,204	34,480,640	(4.67)	(4.72)	(29.46)
21	GAS - Generation	27,663,531	27,993,569	28,889,477	46,920,187	1.19	3.20	62.41
22	OTHER - C.T.	0	9,402	1,350	4,951	100.00	(85.64)	266.74
23	TOTAL (MMBtu)	81,478,663	79,305,037	77,773,031	81,405,778	(2.67)	(1.93)	4.67
	GENERATION MIX (% MWh)							
24	COAL + GAS B.L. + OIL B.L.	56.12	52.71	50.87	33.67	(6.08)	(3.49)	(33.81)
25	GAS - Generation	42.74	46.07	47.92	63.30	7.79	4.02	32.10
26	LANDFILL GAS	0.26	0.28	0.28	0.26	7.69	0.00	(7.14)
27	OTHER - C.T.	0.00	0.01	0.00	0.00	100.00	(100.00)	0.00
28	OTHER GENERATION	0.87	0.93	0.93	0.72	6.90	0.00	(22.58)
29	Solar	0.00	0.00	0.00	2.04	0.00	0.00	100.00
30	TOTAL (% MWH)	100.00	100.00	100.00	100.00	0.00	0.00	0.00

GULF POWER COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

PROPOSED FOR THE PERIOD: JANUARY 2020 - DECEMBER 2020

(1)	(2) (3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
						% Change		
LINE	LINE DESCRIPTION	2017	2018	2019	2020	2018	2019	2019 to 2020
	FUEL COST PER UNIT							
31	LIGHTER OIL B.L. ($/BBL)	97.25	70.68	97.25	89.10	(27.32)	37.59	(8.38)
32	COAL ($/TON)	66.08	61.61	66.08	63.84	(6.76)	7.26	(3.39)
33	GAS +B.L. ($/MCF)	3.72	4.25	3.72	3.46	14.25	(12.47)	(6.99)
34	OTHER - C.T.	95.06	96.61	95.06	92.07	1.63	(1.60)	(3.15)
	FUEL COST ($ / MMBtu)							
35	COAL + GAS B.L. + OIL B.L.	2.96	2.83	2.96	3.00	(4.39)	4.59	1.35
36	GAS - Generation	3.65	4.05	3.65	3.39	10.96	(9.88)	(7.12)
37	OTHER - C.T.	16.27	16.49	16.27	15.73	1.35	(1.33)	(3.32)
38	TOTAL ($/MMBtu)	3.22	3.26	3.22	3.23	1.24	(1.23)	0.31
	BTU BURNED (Btu / kWh)							
39	COAL + GAS B.L. + OIL B.L.	10,968	11,120	10,968	10,925	1.39	(1.37)	(0.39)
40	GAS - Generation	6,883	6,943	6,883	7,907	0.87	(0.86)	14.88
41	OTHER - C.T.	18,750	13,991	14,063	11,901	(25.38)	0.51	(15.37)
42	TOTAL (Btu/kWh)	8,987	9,172	8,986	8,770	2.06	(2.03)	(2.40)
	FUEL COST (¢ / kWh)							
43	COAL + GAS B.L. + OIL B.L.	3.09	3.15	3.25	3.28	1.94	3.17	0.92
44	GAS - Generation	2.73	2.81	2.52	2.68	2.93	(10.32)	6.35
45	LANDFILL GAS	3.13	3.38	3.00	4.05	7.99	(11.24)	35.00
46	OTHER - C.T.	0.00	23.08	22.88	18.72	100.00	(0.87)	(18.18)
47	OTHER GENERATION	3.09	3.57	2.94	2.73	15.53	(17.65)	(7.14)
48	TOTAL (¢ / kWh)	2.94	3.00	2.90	2.83	2.04	(3.33)	(2.41)

Schedule CCE-1

Projected Purchased Power Capacity Payments / (Receipts)
Gulf Power Company

TO BE INCLUDED IN THE PERIOD JANUARY 2020 - DECEMBER 2020

Line No.	Line Descritpiton	January Projection	February Projection	March Projection	April Projection	May Projection	June Projection	July Projection	August Projection	September Projection	October Projection	November Projection	December Projection	TOTAL
1	Projected IIC Payments / (Receipts)	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Capacity Payments / (Receipts)	7,162,992	7,162,992	7,162,992	7,162,992	7,162,992	7,162,992	7,148,252	7,148,252	7,148,252	7,148,252	7,148,252	7,148,252	85,867,467
3	Projected Transmission Revenue	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(6,000)
4	Total Projected Capacity Payments / (Receipts)	7,162,492	7,162,492	7,162,492	7,162,492	7,162,492	7,162,492	7,147,752	7,147,752	7,147,752	7,147,752	7,147,752	7,147,752	85,861,467
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	Projected Jurisdictional Capacity Payments / (Receipts)	6,964,397	6,964,397	6,964,397	6,964,397	6,964,397	6,964,397	6,950,065	6,950,065	6,950,065	6,950,065	6,950,065	6,950,065	83,486,772
8	True-Up ($)													237,948
9	Total Jurisdictional Amount to be Recovered (Line 7 + Line 8) ($)													83,724,720
10	Revenue Tax Multiplier													1.00072
11	Total Recoverable Capacity Payments / (Receipts) (Line 9 x Line 10) ($)													83,785,002

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,892,069.55	97.23427%
FERC	53,817.94	2.76573%
Total	1,945,887.49	100.00000%

Schedule CCE-1A

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP

TO BE INCLUDED IN THE PERIOD JANUARY 2020 - DECEMBER 2020

1.	Estimated over/(under)-recovery, January 2019 - December 2019 (Schedule CCE-1B, Line 16 + Line 19)	(622,746)
2.	Final over/(under)-recovery, January 2018 - December 2018 (Exhibit CSB-1, Schedule CCA-1)	384,798
3.	Total over/(under)-recovery (Line 1 + 2) (To be included in January 2020 - December 2020)	($237,948)
4.	Jurisdictional kWh sales, January 2020 - December 2020	10,951,029,000
5.	True-up factor (Line 3 / Line 4) x 100 (¢/kWh)	0.0022

SCHEDULE CCE-1B

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED TRUE-UP AMOUNT
ACTUAL FOR THE PERIOD JANUARY 2019 - JUNE 2019 / ESTIMATED FOR JULY 2019 - DECEMBER 2019

Line No.	Line Descritpiton	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Projection	August Projection	September Projection	October Projection	November Projection	December Projection	TOTAL
1	IIC Payments/(Receipts)	24,045	16,194	(2,995)	(3,628)	(2,995)	(2,995)	0	0	0	0	0	0	27,626
2	Other Capacity Payments / (Receipts)	7,161,383	7,181,450	7,181,449	7,181,449	7,266,193	7,198,831	7,163,330	7,163,330	7,163,330	7,163,330	7,163,330	7,163,330	86,150,733
3	Transmission Revenue	(726)	(541)	(541)	(681)	(151)	(311)	(500)	(500)	(500)	(500)	(500)	(500)	(5,951)
4	Scherer/Flint Credit	(682,078)	(610,980)	(589,922)	(533,987)	(720,007)	(651,768)	(775,216)	(798,886)	(851,222)	(857,561)	(866,108)	(785,065)	(8,722,800)
5	Total Net Capacity Payments/(Receipts)	6,502,624	6,586,123	6,587,991	6,643,153	6,543,040	6,543,757	6,387,614	6,363,944	6,311,608	6,305,269	6,296,722	6,377,765	77,449,608
6	Jurisdictional %	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
7	Jurisdictional Capacity Payments/(Receipts)	6,319,430	6,400,577	6,402,392	6,456,000	6,358,708	6,359,404	6,207,660	6,184,657	6,133,795	6,127,635	6,119,329	6,198,089	75,267,676
8	Retail KWH Sales							1,182,325,000	1,171,710,000	1,004,542,000	848,931,000	731,492,000	827,032,000	
9	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.672	0.672	0.672	0.672	0.672	0.672	
10	Capacity Cost Recovery Revenues	5,699,684	4,374,885	4,856,216	4,880,950	6,633,211	7,475,622	7,945,224	7,873,891	6,750,522	5,704,816	4,915,626	5,557,655	72,668,302
11	Revenue Taxes (Line 10 x .00072)	4,104	3,150	3,496	3,514	4,776	5,382	5,721	5,669	4,860	4,107	3,539	4,002	52,320
12	True-Up Provision	169,499	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	169,501	2,034,010
13	Capacity Cost Recovery Revenues (net of Revenue Taxes)	5,865,079	4,541,236	5,022,220	5,046,937	6,797,936	7,639,741	8,109,004	8,037,723	6,915,163	5,870,210	5,081,588	5,723,154	74,649,992
14	Over/(Under) Recovery	(454,351)	(1,859,341)	(1,380,172)	(1,409,063)	439,228	1,280,337	1,901,344	1,853,066	781,368	(257,425)	(1,037,741)	(474,935)	(617,685)
15	Interest Provision	4,241	1,576	(2,044)	(5,256)	(6,483)	(4,996)	(2,182)	1,115	3,336	3,521	1,948	163	(5,061)
16	Total Estimated True-Up for the Period													(622,746)
17	Beginning Balance True-Up & Interest Provision	2,418,808	1,799,199	(228,067)	(1,779,784)	(3,363,604)	(3,100,360)	(1,994,520)	(264,859)	1,419,821	2,035,024	1,611,619	406,325	2,418,808
18	True-Up Collected/(Refunded)	(169,499)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(169,501)	(2,034,010)
19	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
20	End of Period TOTAL Net True-Up	1,799,199	(228,067)	(1,779,784)	(3,363,604)	(3,100,360)	(1,994,520)	(264,859)	1,419,821	2,035,024	1,611,619	406,325	(237,948)	(237,948)

Gulf Power Company
Calculation of Purchased Power Capacity Cost Recovery Factors

TO BE INCLUDED IN THE PERIOD JANUARY 2020 - DECEMBER 2020

Line No.	Rate Class	A Average 12 CP Load Factor at Meter	B Projected KWH Sales at Meter	C Projected Avg 12 CP KW at Meter	D Demand Loss Expansion Factor	E Energy Loss Expansion Factor	F Projected KWH Sales at Generation	G Projected Avg 12 CP KW at Generation	H Percentage of KWH Sales at Generation	I Percentage of 12 CP KW Demand at Generation
1	RS, RSVP, RSTOU	58.270328%	5,468,715,000	1,068,429	1.00609343	1.00559591	5,499,317,437	1,074,939	50.22061%	57.87765%
2	GS	57.224449%	302,467,000	60,173	1.00608241	1.00559477	304,159,233	60,539	2.77763%	3.25960%
3	GSD, GSDT, GSTOU	74.102156%	2,428,641,000	373,113	1.00590017	1.00544671	2,441,869,103	375,314	22.29953%	20.20794%
4	LP, LPT	85.094449%	879,247,000	117,630	0.98747379	0.99210885	872,308,730	116,156	7.96606%	6.25417%
5	PX, PXT, RTP, SBS	84.969370%	1,720,313,000	230,490	0.96884429	0.97666479	1,680,169,135	223,309	15.34356%	12.02358%
6	OS - I / II	767.743332%	104,803,000	1,554	1.00619545	1.00560119	105,390,022	1,564	0.96244%	0.08419%
7	OS-III	98.645916%	46,843,000	5,406	1.00617773	1.00558881	47,104,797	5,439	0.43017%	0.29287%
9	TOTAL		10,951,029,000	1,856,795			10,950,318,457	1,857,261	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor at meterbased on actual 2018 load research data.
Col C - 8,784 is the number of hours in 12 months

Gulf Power Company
Calculation of Purchased Power Capacity Cost Recovery Factors

TO BE INCLUDED IN THE PERIOD JANUARY 2020 - DECEMBER 2020

		A	B	C	D	E	F	G	H	I
Line No.	Rate Class	Percentage of KWH Sales at Generation	Percentage of 12 CP KW Demand at Generation	Energy-Related Costs	Demand-Related Costs	Total Capacity Costs	Projected KWH Sales at Meter	Cost Recovery Factors	Projected KW at Meter	Costs Recovery Factors
1	RS, RSVP, RSTOU	50.22061%	57.87765%	3,236,719	44,762,575	47,999,294	5,468,715,000	0.878		
2	GS	2.77763%	3.25960%	179,018	2,520,975	2,699,993	302,467,000	0.893		
3	GSD, GSDT, GSTOU	22.29953%	20.20794%	1,437,205	15,628,821	17,066,026	2,428,641,000	0.703		
4	LP, LPT	7.96606%	6.25417%	513,413	4,836,975	5,350,388	879,247,000	0.000	1,835,156	2.92
5	PX, PXT, RTP, SBS	15.34356%	12.02358%	988,892	9,299,037	10,287,929	1,720,313,000	0.598		
6	OS - I / II	0.96244%	0.08419%	62,029	65,113	127,142	104,803,000	0.121		
7	OS-III	0.43017%	0.29287%	27,724	226,506	254,230	46,843,000	0.543		
9	TOTAL	100.00000%	100.00000%	$6,445,000	$77,340,002	$83,785,002	10,951,029,000	0.765	1,835,156	2.92

SCHEDULE CCE-4

Gulf Power Company
Projected 2020 Capacity Contracts

	(A)	(B)	(C)
	Term		Contract
Contract/Counterparty	Start	End [1]	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**

	Capacity Costs Description	January Projection	February Projection	March Projection	April Projection	May Projection	June Projection	July Projection	August Projection	September Projection	October Projection	November Projection	December Projection	TOTAL
9	Southern Intercompany Interchange	0	0	0	0	0	0	0	0	0	0	0	0	0
10	*PPAs*													
11	Shell Energy N.A. (U.S.), LP													
12	*Other*													
13	South Carolina PSA													
14	Total	7,162,992	7,162,992	7,162,992	7,162,992	7,162,992	7,162,992	7,148,252	7,148,252	7,148,252	7,148,252	7,148,252	7,148,252	85,867,467

	Capacity MW Description	January Projection	February Projection	March Projection	April Projection	May Projection	June Projection	July Projection	August Projection	September Projection	October Projection	November Projection	December Projection
15	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
16	*PPAs*												
17	Shell Energy N.A. (U.S.), LP	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0
18	*Other*												
19	South Carolina PSA												

20 (1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE

Aug 2018 - Dec 2018 Hedging Settlement
Activity Report Summary

	Month		Loss/(Gain)
1.	August 2018	$	1,383,860
2.	September 2018	$	1,280,200
3.	October 2018	$	989,160
4.	November 2018	$	631,600
5.	December 2018	$	(1,235,000)
6.	August - December 2018 Total	$	3,049,820

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 57
PARTY: GULF POWER – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-6

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	**Deal Id**	**Settlement Type**	**We Pay Index**	**We Pay Price**	**They Pay Index**	**They Pay Price**	**Settlement Source**	**Hedge Month**	**Opco Deal Volume**	**Dollar Amount**
1	MERRIL	9187	Swaps	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	08/2018	50,000	[redacted]
2	SHELLTRADE	9239	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	40,000	
3	JPMORG	9260	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	60,000	
4	MERRIL	9271	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	60,000	
5	MERRIL	9288	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	70,000	
6	MERRIL	9345	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	100,000	
7	JPMORG	9366	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	60,000	
8	JPMORG	9385	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	50,000	
9	MERRIL	9444	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	50,000	
10	JPMORG	9494	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	40,000	
11	JPMORG	9539	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	40,000	
12	JPMORG	9670	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	40,000	
13	MERRIL	9815	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	60,000	
14	JPMORG	9827	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	60,000	
15	JPMORG	9849	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	60,000	
16	JPMORG	9889	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	60,000	
17	MERRIL	9920	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	60,000	
18	JPMORG	9926	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	60,000	
19	JPMORG	9930	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	30,000	
20	MERRIL	9937	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	20,000	
21	JPMORG	9940	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	20,000	
22	JPMORG	8654	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	40,000	
23	MERRIL	8668	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	40,000	
24	JPMORG	8707	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	40,000	
25	MERRIL	8747	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	50,000	
26	JPMORG	8768	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	30,000	
27	JPMORG	8777	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	20,000	
28	SHELLTRADE	8785	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	20,000	
29	SHELLTRADE	8809	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	30,000	
30	JPMORG	8899	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	20,000	
31	JPMORG	8951	Swaps	Fixed		Nymex LD HH		Nymex	08/2018	40,000	
32										**Total**	**$1,383,860.00**

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	**Deal Id**	**Settlement Type**	**We Pay Index**	**We Pay Price**	**They Pay Index**	**They Pay Price**	**Settlement Source**	**Hedge Month**	**Opco Deal Volume**	**Dollar Amount**
1	MERRIL	9187	Swaps	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	09/2018	50,000	[redacted]
2	SHELLTRADE	9239	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	40,000	
3	JPMORG	9260	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	60,000	
4	MERRIL	9271	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	60,000	
5	MERRIL	9288	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	70,000	
6	MERRIL	9345	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	100,000	
7	JPMORG	9366	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	60,000	
8	JPMORG	9385	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	50,000	
9	MERRIL	9444	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	50,000	
10	JPMORG	9494	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	40,000	
11	JPMORG	9539	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	40,000	
12	JPMORG	9670	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	40,000	
13	MERRIL	9815	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	60,000	
14	JPMORG	9827	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	60,000	
15	JPMORG	9849	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	60,000	
16	JPMORG	9889	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	60,000	
17	MERRIL	9920	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	60,000	
18	JPMORG	9926	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	60,000	
19	JPMORG	9930	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	30,000	
20	MERRIL	9937	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	20,000	
21	JPMORG	9940	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	20,000	
22	MERRIL	8747	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	50,000	
23	JPMORG	8768	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	30,000	
24	JPMORG	8777	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	20,000	
25	SHELLTRADE	8785	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	20,000	
26	JPMORG	8654	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	40,000	
27	MERRIL	8668	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	40,000	
28	JPMORG	8707	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	40,000	
29	SHELLTRADE	8809	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	30,000	
30	JPMORG	8899	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	20,000	
31	JPMORG	8951	Swaps	Fixed		Nymex LD HH		Nymex	09/2018	40,000	
32										**Total**	**$1,280,200.00**

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	**Deal Id**	**Settlement Type**	**We Pay Index**	**We Pay Price**	**They Pay Index**	**They Pay Price**	**Settlement Source**	**Hedge Month**	**Opco Deal Volume**	**Dollar Amount**
1	MERRIL	9187	Swaps	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	10/2018	50,000	[redacted]
2	SHELLTRADE	9239	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	40,000	
3	JPMORG	9260	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	60,000	
4	MERRIL	9271	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	60,000	
5	MERRIL	9288	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	70,000	
6	MERRIL	9345	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	100,000	
7	JPMORG	9366	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	60,000	
8	JPMORG	9385	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	50,000	
9	MERRIL	9444	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	50,000	
10	JPMORG	9494	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	40,000	
11	JPMORG	9539	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	40,000	
12	JPMORG	9670	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	40,000	
13	MERRIL	9815	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	60,000	
14	JPMORG	9827	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	60,000	
15	JPMORG	9849	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	60,000	
16	JPMORG	9889	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	60,000	
17	MERRIL	9920	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	60,000	
18	JPMORG	9926	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	60,000	
19	JPMORG	9930	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	30,000	
20	MERRIL	9937	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	20,000	
21	JPMORG	9940	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	20,000	
22	MERRIL	8747	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	50,000	
23	JPMORG	8768	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	30,000	
24	JPMORG	8777	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	20,000	
25	SHELLTRADE	8785	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	20,000	
26	JPMORG	8707	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	40,000	
27	SHELLTRADE	8809	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	30,000	
28	JPMORG	8899	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	20,000	
29	JPMORG	8951	Swaps	Fixed		Nymex LD HH		Nymex	10/2018	40,000	
30										**Total**	**$989,160.00**

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	**Deal Id**	**Settlement Type**	**We Pay Index**	**We Pay Price**	**They Pay Index**	**They Pay Price**	**Settlement Source**	**Hedge Month**	**Opco Deal Volume**	**Dollar Amount**
1	MERRIL	9187	Swaps	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	11/2018	50,000	[redacted]
2	SHELLTRADE	9239	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	40,000	
3	JPMORG	9260	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	60,000	
4	MERRIL	9271	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	60,000	
5	MERRIL	9288	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	70,000	
6	MERRIL	9345	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	100,000	
7	JPMORG	9366	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	60,000	
8	JPMORG	9385	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	50,000	
9	MERRIL	9444	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	50,000	
10	JPMORG	9494	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	40,000	
11	JPMORG	9539	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	40,000	
12	JPMORG	9670	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	40,000	
13	MERRIL	9815	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	60,000	
14	JPMORG	9827	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	60,000	
15	JPMORG	9849	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	60,000	
16	JPMORG	9889	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	60,000	
17	MERRIL	9920	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	60,000	
18	JPMORG	9926	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	60,000	
19	JPMORG	9930	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	30,000	
20	MERRIL	9937	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	20,000	
21	JPMORG	9940	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	20,000	
22	JPMORG	8777	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	20,000	
23	SHELLTRADE	8785	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	20,000	
24	SHELLTRADE	8809	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	30,000	
25	JPMORG	8899	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	20,000	
26	JPMORG	8951	Swaps	Fixed		Nymex LD HH		Nymex	11/2018	40,000	
27										**Total**	**$631,600.00**

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	**Deal Id**	**Settlement Type**	**We Pay Index**	**We Pay Price**	**They Pay Index**	**They Pay Price**	**Settlement Source**	**Hedge Month**	**Opco Deal Volume**	**Dollar Amount**
1	MERRIL	9187	Swaps	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	12/2018	50,000	[redacted]
2	SHELLTRADE	9239	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	40,000	
3	JPMORG	9260	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	60,000	
4	MERRIL	9271	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	60,000	
5	MERRIL	9288	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	70,000	
6	MERRIL	9345	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	100,000	
7	JPMORG	9366	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	60,000	
8	JPMORG	9385	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	50,000	
9	MERRIL	9444	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	50,000	
10	JPMORG	9494	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	40,000	
11	JPMORG	9539	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	40,000	
12	JPMORG	9670	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	40,000	
13	MERRIL	9815	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	60,000	
14	JPMORG	9827	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	60,000	
15	JPMORG	9849	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	60,000	
16	JPMORG	9889	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	60,000	
17	MERRIL	9920	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	60,000	
18	JPMORG	9926	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	60,000	
19	JPMORG	9930	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	30,000	
20	MERRIL	9937	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	20,000	
21	JPMORG	9940	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	20,000	
22	JPMORG	8777	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	20,000	
23	SHELLTRADE	8785	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	20,000	
24	SHELLTRADE	8809	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	30,000	
25	JPMORG	8899	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	20,000	
26	JPMORG	8951	Swaps	Fixed		Nymex LD HH		Nymex	12/2018	40,000	
27										**Total**	**($1,235,000.00)**

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE

Jan 2019 - Jul 2019 Hedging Settlement
Activity Report Summary

	Month	Savings/(Cost)
1.	January 2019	$ (142,790)
2.	February 2019	$ (454,190)
3.	March 2019	$ (496,940)
4.	April 2019	$ (560,840)
5.	May 2019	$ (626,990)
6.	June 2019	$ (596,840)
7.	July 2019	$ (750,740)
8.	January - July 2019 Total	$ (3,629,330)
9.	2019 YTD Hedging Savings/(Cost)	$ (3,629,330)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 58
PARTY: GULF POWER – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-7

GULF POWER COMPANY
Hedging Activity Report
January 2019 - July 2019

Line No.	A Contract Month	B Counterparty	C Deal Type	D Deal ID	E Description	F Fixed Price	G Receive Price	I Volume	J Period-End Gain/(Loss)
1	201901	Citigroup Energy Inc. [CITI INC]	Swap	2462168	[redacted]			30,000	[redacted]
2	201901	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462021				40,000	
3	201901	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462023				60,000	
4	201901	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462024				40,000	
5	201901	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462025				40,000	
6	201901	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462041				40,000	
7	201901	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462094				30,000	
8	201901	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462128				40,000	
9	201901	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461994				60,000	
10	201901	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461996				30,000	
11	201901	Merrill Lynch Commodities, Inc. [MLC]	Swap	2462000				40,000	
12							TOTAL	450,000	(142,790.00)
13	201902	Citigroup Energy Inc. [CITI INC]	Swap	2462168	[redacted]			30,000	[redacted]
14	201902	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462021				40,000	
15	201902	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462023				60,000	
16	201902	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462024				40,000	
17	201902	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462025				40,000	
18	201902	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462041				40,000	
19	201902	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462094				30,000	
20	201902	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462128				40,000	
21	201902	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461994				60,000	
22	201902	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461996				30,000	
23	201902	Merrill Lynch Commodities, Inc. [MLC]	Swap	2462000				40,000	
24							TOTAL	450,000	(454,190.00)
25	201903	Citigroup Energy Inc. [CITI INC]	Swap	2462168	[redacted]			30,000	[redacted]
26	201903	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462021				40,000	
27	201903	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462023				60,000	
28	201903	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462024				40,000	
29	201903	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462025				40,000	
30	201903	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462041				40,000	
31	201903	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462094				30,000	
32	201903	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462128				40,000	
33	201903	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461994				60,000	
34	201903	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461996				30,000	
35	201903	Merrill Lynch Commodities, Inc. [MLC]	Swap	2462000				40,000	
36							TOTAL	450,000	(496,940.00)
37	201904	Citigroup Energy Inc. [CITI INC]	Swap	2462168	[redacted]			30,000	[redacted]
38	201904	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462021				40,000	
39	201904	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462023				60,000	
40	201904	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462024				40,000	
41	201904	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462025				40,000	
42	201904	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462041				40,000	
43	201904	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462094				30,000	
44	201904	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462128				40,000	
45	201904	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461994				60,000	
46	201904	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461996				30,000	
47	201904	Merrill Lynch Commodities, Inc. [MLC]	Swap	2462000				40,000	
48							TOTAL	450,000	(560,840.00)

GULF POWER COMPANY
Hedging Activity Report
January 2019 - July 2019

	A	B	C	D	E	F	G	I	J
Line No.	Contract Month	Counterparty	Deal Type	Deal ID	Description	Fixed Price	Receive Price	Volume	Period-End Gain/(Loss)
1	201905	Citigroup Energy Inc. [CITI INC]	Swap	2462168	[redacted]			30,000	[redacted]
2	201905	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462021				40,000	
3	201905	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462023				60,000	
4	201905	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462024				40,000	
5	201905	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462025				40,000	
6	201905	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462041				40,000	
7	201905	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462094				30,000	
8	201905	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462128				40,000	
9	201905	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461994				60,000	
10	201905	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461996				30,000	
11	201905	Merrill Lynch Commodities, Inc. [MLC]	Swap	2462000				40,000	
12							TOTAL	450,000	(626,990.00)
13	201906	Citigroup Energy Inc. [CITI INC]	Swap	2462168	[redacted]			30,000	[redacted]
14	201906	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462021				40,000	
15	201906	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462023				60,000	
16	201906	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462024				40,000	
17	201906	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462025				40,000	
18	201906	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462041				40,000	
19	201906	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462094				30,000	
20	201906	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462128				40,000	
21	201906	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461994				60,000	
22	201906	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461996				30,000	
23	201906	Merrill Lynch Commodities, Inc. [MLC]	Swap	2462000				40,000	
24							TOTAL	450,000	(596,840.00)
25	201907	Citigroup Energy Inc. [CITI INC]	Swap	2462168	[redacted]			30,000	[redacted]
26	201907	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462021				40,000	
27	201907	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462023				60,000	
28	201907	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462024				40,000	
29	201907	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462025				40,000	
30	201907	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462041				40,000	
31	201907	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462094				30,000	
32	201907	JPMorgan Chase Bank, NA [JPM CHASE]	Swap	2462128				40,000	
33	201907	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461994				60,000	
34	201907	Merrill Lynch Commodities, Inc. [MLC]	Swap	2461996				30,000	
35	201907	Merrill Lynch Commodities, Inc. [MLC]	Swap	2462000				40,000	
36							TOTAL	450,000	(750,740.00)

EXHIBIT TO THE TESTIMONY OF

C. L. NICHOLSON

IN FPSC DOCKET 20190001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 59
PARTY: GULF POWER – (DIRECT)
DESCRIPTION: C. L. Nicholson CLN-1

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2018 - DECEMBER 2018 PERIOD

Additions and Corrections to Outages Previously Reported
for the January 2018 - December 2018 Period

Date	Unit	Change	Outage Type	Hours	MW	Description
April filing	Daniel 1	Added planned derate.	PMO	383.6	35.8	Event in April added after filing. Decreased EAF.
April filing	Daniel 2	Added planned derate.	PMO	516.7	36.0	Event in April added after filing. Decreased EAF.
January filing	Scherer 3	Reduced event duration.	FFO	2.8	860.0	Increased EAF.

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for January 2018 - December 2018

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 7	1	03/03/18 - 04/22/18	1223.0	03/02/18 - 05/01/18	1431.4
Crist 7	2	N/A	0.0	08/24/18 - 09/09/18	365.4
Smith 3	3	05/05/18 - 05/13/18	216.0	05/16/18 - 05/26/18	232.0
Smith 3	5	10/13/18 - 10/21//18	216.0	N/A	0.0
Daniel 1	4	03/01/18 - 04/16/18	1127.0	03/01/18 - 04/26/18	1353.6
Daniel 2	1	03/24/18 - 04/01/18	216.0	03/24/18 - 04/02/18	216.0

* Planned outage hours in the January 2018 - December 2018 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.
5. The outage was cancelled due to Hurricane Michael.

Calculation of Actual Equivalent Availability
for January 2018 - December 2018
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	2.8	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	144.5	0.0	3.4	150.7
EFOH	0.4	0.0	0.0	0.7	12.7	0.0	
	0.0	0.1	0.0	0.0	0.0	17.7	31.6
MOH	0.0	0.0	51.9	0.0	221.0	0.0	
	0.0	0.0	0.0	0.0	0.0	81.6	354.5
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	2.1	0.0	0.0	0.0	0.0	2.1
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
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

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(150.7 + 31.6 + 354.5 + 2.1)}{(8760.0 - 0.0 - 0.0)}$$

$$EUOR = 0.0615$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 441.0

$$EA = \left[1 - \frac{(0.0 + 0.0615\ (8760.0 - 0.0 - 441.0))}{8760.0} \right] \times 100 = 94.2\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2018 - December 2018
Based on Target Planned Outage Hours
Crist 7

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	114.6	0.8	
	31.5	0.0	4.6	0.0	5.1	0.0	156.6
EFOH	0.0	0.0	0.0	0.0	50.0	30.3	
	0.0	0.0	0.0	0.0	0.0	0.0	80.3
MOH	391.3	407.9	48.0	0.0	36.3	106.7	
	64.4	0.0	0.0	0.0	0.0	0.0	1054.6
EMOH	0.0	0.0	0.0	0.0	0.0	20.4	
	0.0	0.0	0.0	0.0	0.0	0.0	20.4
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	0.0	695.0	720.0	16.4	0.0	
	0.0	170.4	195.0	0.0	0.0	0.0	1796.8
RSH	0.0	144.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	144.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(156.6 + 80.3 + 1054.6 + 20.4)}{(8760.0 - 1796.8 - 144.0)}$$

EUOR = 0.1924

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1227.0

Target RSH* = 2322.0

$$EA = \left[1 - \frac{(1227.0 + 0.1924\ (8760.0 - 1227.0 - 2322.0))}{8760.0} \right] \times 100 = 74.5\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2018 - December 2018
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	3.4	0.0	0.0	0.0	2.3	6.6	
	0.0	0.0	0.0	32.9	0.0	0.0	45.1
EFOH	102.7	0.0	0.0	0.0	2.1	3.1	
	1.6	73.6	124.4	69.9	2.6	0.0	380.0
MOH	0.0	0.0	0.0	0.0	146.2	0.0	
	0.0	18.2	42.7	79.3	24.6	41.1	352.0
EMOH	0.9	0.0	0.0	7.8	60.2	106.0	
	127.5	35.9	3.3	83.8	102.4	80.9	608.7
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	0.0	743.0	610.6	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1353.6
RSH	0.0	531.6	0.0	0.0	0.0	0.0	
	0.0	237.5	0.0	75.4	0.0	203.7	1048.1

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(45.1 + 380.0 + 352.0 + 608.7)}{(8760.0 - 1353.6 - 1048.1)}$$

$$EUOR = 0.2179$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1127.0

Target RSH* = 2293.0

$$EA = \left[1 - \frac{(1127.0 + 0.2179\ (8760.0 - 1127.0 - 2293.0))}{8760.0} \right] \times 100 = 73.9\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2018 - December 2018
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	8.7	0.0	12.2	
	0.0	1.8	0.0	0.0	0.0	0.0	22.7
EFOH	10.4	0.0	0.0	0.0	0.0	2.6	
	32.2	56.9	106.6	116.3	0.9	32.4	358.3
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	33.9	26.2	95.0	0.0	0.0	155.1
EMOH	0.0	0.0	0.0	17.9	46.3	67.9	
	90.7	41.4	69.7	85.2	110.4	88.8	618.3
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	0.0	192.0	24.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	216.0
RSH	208.6	505.7	485.7	544.8	0.0	0.0	
	0.0	0.0	0.0	24.0	98.4	220.6	2087.8

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(22.7 + 358.3 + 155.1 + 618.3)}{(8760.0 - 216.0 - 2087.8)}$$

EUOR = 0.1788

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 216.0

Target RSH* = 1070.0

$$EA = \left[1 - \frac{(216.0 + 0.1788\ (8760.0 - 216.0 - 1070.0))}{8760.0} \right] \times 100 = 82.3\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2018 - December 2018
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	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	534.9	35.0	0.0	569.8
EFOH	0.8	1.5	0.0	0.0	0.0	0.3	
	0.0	0.6	3.4	0.0	119.1	31.9	157.6
MOH	0.0	0.0	17.5	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	17.5
EMOH	8.0	0.0	8.7	0.0	42.4	0.0	
	0.0	0.0	11.1	0.0	1.8	13.5	85.5
PH	744.0	672.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	232.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	232.0
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	3.8	0.0	3.8

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(569.8 + 157.6 + 17.5 + 85.5)}{(8760.0 - 232.0 - 3.8)}$$

$$EUOR = 0.0974$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 432.0

Target RSH* = 777.0

$$EA = \left[1 - \frac{(432.0 + 0.0974\ (8760.0 - 432.0 - 777.0))}{8760.0} \right] \times 100 = 86.7\ \%$$

Note: Please refer to page 9 of this Schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for January 2018 - December 2018

(1) Unit	(2) Equivalent Availability Target*	(3) Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	(4) Minimum or Maximum Attainable Equivalent Availability*	(5) Availability Points***
Scherer 3	97.2	94.2	96.0	-10.00
Crist 7	82.1	74.5	80.6	-10.00
Daniel 1	82.2	73.9	81.7	-10.00
Daniel 2	90.7	82.3	88.0	-10.00
Smith 3	93.2	86.7	92.3	-10.00

* As appropriate from page 5, Schedule 3 of Exhibit to C. L. Nicholson's September 1, 2017 GPIF Testimony in Docket 20170001-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 2018 - December 2018

Scherer 3

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	530820.0	322534.0	333516.0	430838.0	378280.0	529256.0	
	583612.0	575636.0	633416.0	482060.0	584994.0	411556.0	5796518.0
BTU/Lb*	8336.6	8269.6	8368.4	8323.3	8228.3	8254.7	
	8287.5	8286.1	8381.3	8397.8	8343.6	8261.8	8314.6
Coal, MMBTU	4425228.9	2667230.4	2791004.3	3585998.4	3112606.1	4368873.9	
	4836677.1	4769794.2	5308818.2	4048226.0	4880978.9	3400178.5	48195614.9
Oil, MMBTU	3828.2	533.8	3454.8	422.1	7650.5	0.0	
	63.8	91.3	72.1	5639.4	1.4	11051.6	32809.0
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 **	0.0	0.0	-5373.0	0.0	-5373.0	0.0	
	0.0	0.0	0.0	-10746.0	0.0	-5373.0	-26865.0
Total Fuel Consumption, MMBTU	4429057.1	2667764.2	2789086.1	3586420.5	3114883.6	4368873.9	
	4836740.9	4769885.5	5308890.3	4043119.4	4880980.3	3405857.1	48201558.9
Net MWH Generation***	419053	238089	255178	327050	291198	399280	
	446378	448366	505151	378360	470036	312419	4490558
Average Net Operating Heat Rate	10569	11205	10930	10966	10697	10942	
	10836	10638	10510	10686	10384	10902	10734

* 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 2018 - December 2018

Crist 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	125209.8	35628.3	0.0	0.0	161674.2	187705.1	
	208693.8	185080.0	191014.0	245078.6	242008.0	225198.0	1807289.8
BTU/Lb*	11462.1	11392.5	0.0	0.0	11360.4	11232.3	
	11303.7	11041.7	11339.0	11499.1	11245.0	11282.4	11307.0
Coal, MMBTU	1435161.6	405894.8	0.0	0.0	1836686.5	2108368.0	
	2359006.3	2043589.6	2165904.1	2818181.0	2721381.1	2540783.8	20434956.8
Oil, MMBTU	618.2	343.9	0.0	0.0	4024.1	2092.7	
	3260.5	1013.1	1358.6	166.5	1472.7	291.3	14641.6
Gas, MMBTU	8762.3	857.5	0.0	0.0	15865.8	5205.2	
	0.0	0.0	7302.3	7.5	3032.3	125.2	41158.2
Startup, MMBTU **	-4512.0	0.0	0.0	0.0	-9024.0	-2256.0	
	-4512.0	0.0	-2256.0	0.0	0.0	0.0	-22560.0
Total Fuel Consumption, MMBTU	1440030.1	407096.2	0.0	0.0	1847552.4	2113409.9	
	2357754.8	2044602.7	2172309.0	2818355.0	2725886.1	2541200.3	20468196.5
Net MWH Generation***	139399	39765	0	0	175139	196649	
	225834	198238	202094	276811	263549	235496	1952974
Average Net Operating Heat Rate	10330	10238	---	---	10549	10747	
	10440	10314	10749	10182	10343	10791	10481

* 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 2018 - December 2018

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	155358.0	29022.0	0.0	28302.0	144642.0	185904.0	
	156730.0	96016.0	167230.0	141696.0	162364.0	118724.0	1385988.0
BTU/Lb*	10082.0	8887.8	0.0	9080.4	8922.6	9018.7	
	8817.2	9641.5	9246.0	9240.6	9152.3	8864.9	9199.3
Coal, MMBTU	1566325.2	257942.0	0.0	256992.4	1290585.5	1676619.7	
	1381926.2	925740.1	1546208.7	1309361.6	1486008.0	1052477.4	12750186.8
Oil, MMBTU	11466.8	694.2	0.0	5587.4	5263.0	3834.4	
	232.4	12092.4	44586.7	29267.4	12078.9	8691.8	133795.4
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 **	0.0	0.0	0.0	-2388.7	-2388.7	0.0	
	0.0	-2388.7	-2388.7	-7166.1	0.0	-2388.7	-19109.6
Total Fuel Consumption, MMBTU	1577792.0	258636.2	0.0	260191.1	1293459.8	1680454.1	
	1382158.6	935443.8	1588406.7	1331462.9	1498086.9	1058780.5	12864872.6
Net MWH Generation***	139431	24250	0	20350	112543	143173	
	114932	80281	141790	125646	134181	99225	1135802
Average Net Operating Heat Rate	11316	10665	---	12786	11493	11737	
	12026	11652	11203	10597	11165	10671	11327

* 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 2018 - December 2018

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	143850.0	34662.0	17518.0	32734.0	201220.0	187274.0	
	155698.0	152470.0	176618.0	154032.0	147484.0	113458.0	1517018.0
BTU/Lb*	9437.8	8940.9	9120.2	8998.4	8878.8	8934.8	
	9309.2	9605.2	9167.1	9358.3	9238.1	8906.8	9182.0
Coal, MMBTU	1357624.4	309908.4	159767.4	294554.1	1786600.2	1673263.5	
	1449423.2	1464499.2	1619075.8	1441482.0	1362475.8	1010551.4	13929225.4
Oil, MMBTU	5711.0	974.1	3976.6	9990.7	278.5	13415.1	
	9938.1	28956.3	22155.2	500.9	3990.3	12541.3	112428.1
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	-4777.4	0.0	0.0	
	0.0	-2388.7	-2388.7	0.0	-2388.7	0.0	-16720.9
Total Fuel Consumption, MMBTU	1360946.7	310882.5	161355.3	299767.4	1786878.7	1686678.6	
	1459361.3	1491066.8	1638842.3	1441982.9	1364077.4	1023092.7	14024932.6
Net MWH Generation***	121522	30438	14854	24283	158163	151347	
	124437	129256	146208	132536	118313	90537	1241894
Average Net Operating Heat Rate	11199	10214	10863	12345	11298	11144	
	11728	11536	11209	10880	11529	11300	11293

* 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 2018 - December 2018

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	2698322.5	2236888.6	2591016.7	2566409.5	1615364.3	2484766.3	
	2654276.5	2720196.5	2627729.5	778079.4	2054343.3	2257053.9	27284447.0
Startup, MMBTU **	0.0	0.0	0.0	0.0	-1200.0	0.0	
	0.0	0.0	0.0	0.0	-1200.0	0.0	-2400.0
Total Fuel Consumption, MMBTU	2698322.5	2236888.6	2591016.7	2566409.5	1614164.3	2484766.3	
	2654276.5	2720196.5	2627729.5	778079.4	2053143.3	2257053.9	27282047.0
Net MWH Generation***	387087	324932	362844	382271	234509	352820	
	392225	384575	375931	113598	278860	333935	3923587
Average Net Operating Heat Rate	6971	6884	7141	6714	6883	7043	
	6767	7073	6990	6849	7363	6759	6953

* 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 2018 - December 2018
Adjusted to Target Basis Using Heat Rate
Equations Filed September 1, 2017

Scherer 3

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	10455	10459	10353	10523	10764	10496	
	10460	10454	10481	10491	10525	10505	
2. Target Heat Rate	10634	11195	10908	10865	10923	10652	
at Actual Conditions**	10580	10576	10451	10536	10509	10816	
3. Adjustment to Actual	-179	-736	-555	-342	-159	-156	
Heat Rate (1-2)	-120	-122	30	-45	16	-311	
4. Actual Heat Rate	10569	11205	10930	10966	10696	10942	
(Page X of Sched. 3)	10836	10638	10510	10686	10384	10901	
5. Adjusted Actual	10390	10469	10375	10624	10537	10786	
Heat Rate (4+3)	10716	10516	10540	10641	10400	10590	
6. Net MWH Generation	419053	238089	255178	327050	291198	399280	
	446378	448366	505151	378360	470036	312419	
7. Adjusted Actual Heat Rate for January 2018 - December 2018 =(S (5*6) / S 6)							10553

* From pages 17 & 18, Schedule 3 of Exhibit to C. L. Nicholson's September 1, 2017 GPIF Testimony in Docket 20170001-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 2018 - December 2018
Adjusted to Target Basis Using Heat Rate
Equations Filed September 1, 2017

Crist 7

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	10351	10659	0	0	10589	10466	
	10418	10425	10484	10698	10578	10572	
2. Target Heat Rate	10212	10351	0	0	10653	10589	
at Actual Conditions**	10498	10511	10385	10431	10370	10613	
3. Adjustment to Actual	139	308	0	0	-64	-123	
Heat Rate (1-2)	-80	-86	99	267	208	-41	
4. Actual Heat Rate	10330	10237	0	0	10549	10747	
(Page 3 of Sched. 3)	10440	10314	10749	10182	10343	10791	
5. Adjusted Actual	10469	10545	0	0	10485	10624	
Heat Rate (4+3)	10360	10228	10848	10449	10551	10750	
6. Net MWH Generation	139399	39765	0	0	175139	196649	
	225834	198238	202094	276811	263549	235496	
7. Adjusted Actual Heat Rate for January 2018 - December 2018 =(S (5*6) / S 6)							10532

* From pages 19 & 20, Schedule 3 of Exhibit to C. L. Nicholson's September 1, 2017 GPIF Testimony in Docket 20170001-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 2018 - December 2018
Adjusted to Target Basis Using Heat Rate
Equations Filed September 1, 2017

Daniel 1

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	12833	12295	0	0	12944	12243	
	12140	11714	12206	12180	12248	12290	
2. Target Heat Rate	12002	11713	0	11573	11969	11372	
at Actual Conditions**	12035	11862	11271	11140	11475	11394	
3. Adjustment to Actual	831	582	0	632	975	871	
Heat Rate (1-2)	105	-148	935	1040	773	896	
4. Actual Heat Rate	11315	10665	0	12781	11492	11737	
(Page 4 of Sched. 3)	12026	11643	11199	10594	11164	10670	
5. Adjusted Actual	12146	11247	0	13413	12467	12608	
Heat Rate (4+3)	12131	11495	12134	11634	11937	11566	
6. Net MWH Generation	139431	24250	0	20350	112543	143173	
	114932	80281	141790	125646	134181	99225	
7. Adjusted Actual Heat Rate for January 2018 - December 2018 =(S (5*6) / S 6)							12059

* From pages 21 & 22 , Schedule 3 of Exhibit to C. L. Nicholson's September 1, 2017 GPIF Testimony in Docket 20170001-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 2018 - December 2018
Adjusted to Target Basis Using Heat Rate
Equations Filed September 1, 2017

Daniel 2

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	13100	12007	12722	12928	13224	12842	
	12216	11649	0	12096	11464	12822	
2. Target Heat Rate	11601	11257	11266	12163	11730	11644	
at Actual Conditions**	12227	11925	11268	11078	10817	12107	
3. Adjustment to Actual	1499	750	1456	765	1494	1198	
Heat Rate (1-2)	-11	-276	1161	1018	647	715	
4. Actual Heat Rate	11199	10213	10859	12338	11298	11143	
(Page 5 of Sched. 3)	11726	11533	11208	10880	11529	11299	
5. Adjusted Actual	12698	10963	12315	13103	12792	12341	
Heat Rate (4+3)	11715	11257	12369	11898	12176	12014	
6. Net MWH Generation	121522	30438	14854	24283	158163	151347	
	124437	129256	146208	132536	118313	90537	
7. Adjusted Actual Heat Rate for January 2018 - December 2018 =(S (5*6) / S 6)							12155

* From pages 23 & 24, Schedule 3 of Exhibit to C. L. Nicholson's September 1, 2017 GPIF Testimony in Docket 20170001-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 2018 - December 2018
Adjusted to Target Basis Using Heat Rate
Equations Filed September 1, 2017

Smith 3

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1. Target Heat Rate*	6935	6935	6943	6959	6941	6949	
	6943	6946	6946	6789	6936	6928	
2. Target Heat Rate	6953	6974	6964	6971	6990	6970	
at Actual Conditions**	6949	6954	6952	6791	7028	6997	
3. Adjustment to Actual	-18	-39	-21	-12	-49	-21	
Heat Rate (1-2)	-6	-8	-6	-2	-92	-69	
4. Actual Heat Rate***	6971	6884	6912	6714	6888	7043	
(Page 6 of Sched. 3)	6767	7073	6990	6849	7367	6759	
5. Adjusted Actual	6953	6845	6891	6702	6839	7022	
Heat Rate (4+3)	6761	7065	6984	6847	7275	6690	
6. Net MWH Generation	387087	324932	362844	382271	234509	352820	
	392225	384575	375931	113598	278860	333935	
7. Adjusted Actual Heat Rate for January 2018 - December 2018 =(S (5*6) / S 6)							6905

* From pages 25 & 26, Schedule 3 of Exhibit to C. L. Nicholson's September 1, 2017 GPIF Testimony in Docket 20170001-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 2018 - December 2018

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Scherer 3						
+3						
AKW * 10	565.4	354.3	369.2	454.2	556.8	554.6
	600.0	602.6	701.6	631.1	651.9	474.0
+6						
LSRF * 10	386354.0	144270.6	157814.7	244953.9	371341.3	371426.8
	424885.7	427663.1	542923.0	457944.9	480547.6	281821.6
Crist 7						
+3						
AKW * 10	395.2	331.1	0.0	0.0	303.7	321.1
	348.5	345.6	388.4	372.1	368.1	316.5
+6						
LSRF * 10	166143.2	119479.8	0.0	0.0	105423.2	114968.7
	133168.1	128197.3	162551.1	148506.2	141149.9	106997.0
Daniel 1						
+3						
AKW * 10	188.3	172.7	0.0	186.0	189.0	200.7
	154.5	164.4	209.4	225.8	192.7	198.7
+6						
LSRF * 10	37935.7	30084.3	0.0	43395.0	40674.8	44571.7
	25969.6	29970.8	46225.1	57977.9	43516.3	43639.1
Daniel 2						
+3						
AKW * 10	227.0	183.0	227.6	170.3	212.6	213.8
	167.3	182.5	210.7	212.1	190.0	173.0
+6						
LSRF * 10	59050.5	35431.5	63535.8	33429.0	54712.2	52414.2
	30392.2	37277.5	47906.8	50187.9	44651.9	34581.4
Smith 3						
+3						
AKW * 10	520.3	483.5	500.2	530.9	458.0	490.0
	527.2	516.9	522.1	543.2	408.7	448.8
+6						
LSRF * 10	283941.8	245180.1	274783.0	288168.6	229496.9	251178.0
	280326.6	271400.8	277560.0	295736.8	188065.0	220574.4

Target Heat Rate Equations

Scherer 3 ANOHR = 10^6 / AKW * [532.42 - 83.71 * MAR + 152.71 * MAY]
+ 9,692

Crist 7 ANOHR = 10^6 / AKW * [330.88 - 62.20 * JAN - 68.36 * FEB - 48.28 * MAR - 28.26 * NOV]
+ 9,711 - 0.00043 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [481.17 + 92.71 * JAN + 85.98 * MAY]
+ 8,753 + 0.00100 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * [606.70 + 74.51 * JAN - 120.51 * FEB + 58.65 * MAY + 44.01 * JUN - 44.62 * SEP
- 81.23 * OCT - 185.41 * NOV] + 8,600

Smith 3 ANOHR = 10^6 / AKW * [144.47 + 12.50 * APR - 81.62 * OCT]
+ 6,675

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 2018 - December 2018

(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	10,495	10,553	10,180	0.00
Crist 7	10,503	10,532	10,188	0.00
Daniel 1	12,205	12,059	11,839	2.44
Daniel 2	12,429	12,155	12,056	6.68
Smith 3	6,932	6,905	6,724	0.00

* From page 5, Schedule 3 of Exhibit to C. L. Nicholson's September 1, 2017 GPIF Testimony in Docket 20170001-EI.

** Refer to pages 7 through 11 of this Schedule for calculation.

*** If [(2) - 75] <= (3) <= [(2) + 75] then points = 0

$$\text{If } [\,(2)-(3)-75\,] > 0 \text{ then points} = \frac{(2)-(3)-75}{(2)-(4)-75} * 10$$

$$\text{If } [\,(2)-(3)+75\,] < 0 \text{ then points} = \frac{(2)-(3)+75}{(2)-(4)-75} * 10$$

IV. CALCULATION OF COMPANY GPIF POINTS AND REWARD/PENALTY

Calculation of Heat Rate Points

GPIF Points and Reward or Penalty

for January 2018 - December 2018

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Scherer 3	-10.00	0.002	0.00	0.348
Crist 7	-10.00	0.001	0.00	0.083
Daniel 1	-10.00	0.000	2.44	0.011
Daniel 2	-10.00	0.000	6.68	0.025
Smith 3	-10.00	0.014	0.00	0.516

Company GPIF Points = - 10.00 * 0.002 + 0.00 * 0.348
- 10.00 * 0.001 + 0.00 * 0.083
- 10.00 * 0.000 + 2.44 * 0.011
- 10.00 * 0.000 + 6.68 * 0.025
- 10.00 * 0.014 + 0.00 * 0.516

= 0.02

Company reward/penalty = 0.02 points * $519195 per point

= $10,384

* From page 5, Schedule 3 of Exhibit to C. L. Nicholson's September 1, 2017 GPIF Testimony in Docket 20170001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2018 - DECEMBER 2018 PERIOD

CONTENTS	SCHEDULE 5 PAGE
GPIF Reward/Penalty Table (Actual)	3
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
Actual Unit Performance Data	12
Historic Unit Performance Data	13 - 22
Planned Outage Schedules (Actual)	23

Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2018 - December 2018

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	5995	2998
+ 9	5396	2698
+ 8	4796	2398
+ 7	4197	2098
+ 6	3597	1799
+ 5	2998	1499
+ 4	2398	1199
+ 3	1799	899
+ 2	1199	600
+ 1	600	300
0	0	0
- 1	-593	-297
- 2	-1187	-593
- 3	-1780	-890
- 4	-2373	-1187
- 5	-2967	-1483
- 6	-3560	-1780
- 7	-4153	-2077
- 8	-4746	-2373
- 9	-5340	-2670
- 10	-5933	-2967
	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 2018 - December 2018

Line 1	Beginning of Period Balance of Common Equity	$1,530,833,424
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '18	$1,516,879,565
Line 3	Month of Feb '18	$1,529,162,087
Line 4	Month of Mar '18	$1,535,821,943
Line 5	Month of Apr '18	$1,542,741,588
Line 6	Month of May '18	$1,558,135,796
Line 7	Month of Jun '18	$1,575,428,108
Line 8	Month of Jul '18	$1,562,344,248
Line 9	Month of Aug '18	$1,583,520,726
Line 10	Month of Sep '18	$1,604,255,046
Line 11	Month of Oct '18	$1,581,033,871
Line 12	Month of Nov '18	$1,579,749,690
Line 13	Month of Dec '18	$1,925,821,683
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$1,586,594,444
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	74.4147%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$5,330,245
Line 18	Jurisdictional Sales (KWH)	11,132,382,917
Line 19	Total Territorial Sales (KWH)	11,428,908,305
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	97.4055%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$5,191,951
Line 22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF point level from sheet 7.383.9)	$2,997,500
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF Pt. level) (The lesser of Line 21 and Line 22)	$2,997,500

Issued by: Gulf Power Company

Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2018 - December 2018

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Scherer 3	EAF3	0.2%	-10.00	-0.020
Scherer 3	ANOHR3	34.8%	0.00	0.000
Crist 7	EAF4	0.1%	-10.00	-0.015
Crist 7	ANOHR4	8.3%	0.00	0.000
Daniel 1	EAF5	0.0%	-10.00	0.000
Daniel 1	ANOHR5	1.1%	2.44	0.026
Daniel 2	EAF6	0.0%	-10.00	-0.002
Daniel 2	ANOHR6	2.5%	6.68	0.164
Smith 3	EAF7	1.4%	-10.00	-0.138
Smith 3	ANOHR7	51.6%	0.00	0.000
Gulf Power GPIF Total		100.1%		0.02

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2018 - December 2018

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	12	98.10	+ 10	2,089	10,180
+ 9	11	98.01	+ 9	1,880	10,204
+ 8	10	97.92	+ 8	1,671	10,228
+ 7	8	97.83	+ 7	1,462	10,252
+ 6	7	97.74	+ 6	1,253	10,276
+ 5	6	97.65	+ 5	1,045	10,300
+ 4	5	97.56	+ 4	836	10,324
+ 3	4	97.47	+ 3	627	10,348
+ 2	2	97.38	+ 2	418	10,372
+ 1	1	97.29	+ 1	209	10,396
				0	10,420
0	0	97.20	0	0	10,495
				0	10,570
- 1	(1)	97.08	- 1	(209)	10,594
- 2	(2)	96.96	- 2	(418)	10,618
- 3	(3)	96.84	- 3	(627)	10,642
- 4	(4)	96.72	- 4	(836)	10,666
- 5	(5)	96.60	- 5	(1,045)	10,690
- 6	(6)	96.48	- 6	(1,253)	10,714
- 7	(7)	96.36	- 7	(1,462)	10,738
- 8	(8)	96.24	- 8	(1,671)	10,762
- 9	(9)	96.12	- 9	(1,880)	10,786
- 10	(10)	96.00	- 10	(2,089)	10,810
Weighting Factor:		0.002	Weighting Factor:		0.348

Issued by: Gulf Power Company

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2018 - December 2018

Crist 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	3	83.40	+ 10	500	10,188
+ 9	3	83.27	+ 9	450	10,212
+ 8	2	83.14	+ 8	400	10,236
+ 7	2	83.01	+ 7	350	10,260
+ 6	2	82.88	+ 6	300	10,284
+ 5	2	82.75	+ 5	250	10,308
+ 4	1	82.62	+ 4	200	10,332
+ 3	1	82.49	+ 3	150	10,356
+ 2	1	82.36	+ 2	100	10,380
+ 1	0	82.23	+ 1	50	10,404
				0	10,428
0	0	82.10	0	0	10,503
				0	10,578
- 1	(2)	81.95	- 1	(50)	10,602
- 2	(3)	81.80	- 2	(100)	10,626
- 3	(5)	81.65	- 3	(150)	10,650
- 4	(6)	81.50	- 4	(200)	10,674
- 5	(8)	81.35	- 5	(250)	10,698
- 6	(9)	81.20	- 6	(300)	10,722
- 7	(11)	81.05	- 7	(350)	10,746
- 8	(12)	80.90	- 8	(400)	10,770
- 9	(14)	80.75	- 9	(450)	10,794
- 10	(15)	80.60	- 10	(500)	10,818
Weighting Factor:		0.001	Weighting Factor:		0.083

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2018 - December 2018

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	0	84.50	+ 10	65	11,839
+ 9	0	84.27	+ 9	59	11,868
+ 8	0	84.04	+ 8	52	11,897
+ 7	0	83.81	+ 7	46	11,926
+ 6	0	83.58	+ 6	39	11,955
+ 5	0	83.35	+ 5	33	11,985
+ 4	0	83.12	+ 4	26	12,014
+ 3	0	82.89	+ 3	20	12,043
+ 2	0	82.66	+ 2	13	12,072
+ 1	0	82.43	+ 1	7	12,101
				0	12,130
0	0	82.20	0	0	12,205
				0	12,280
- 1	0	82.15	- 1	(7)	12,309
- 2	0	82.10	- 2	(13)	12,338
- 3	0	82.05	- 3	(20)	12,367
- 4	0	82.00	- 4	(26)	12,396
- 5	0	81.95	- 5	(33)	12,426
- 6	0	81.90	- 6	(39)	12,455
- 7	0	81.85	- 7	(46)	12,484
- 8	0	81.80	- 8	(52)	12,513
- 9	0	81.75	- 9	(59)	12,542
- 10	0	81.70	- 10	(65)	12,571
Weighting Factor:		0.000	Weighting Factor:		0.011

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2018 - December 2018

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	1	92.90	+ 10	147	12,056
+ 9	1	92.68	+ 9	132	12,086
+ 8	1	92.46	+ 8	118	12,116
+ 7	1	92.24	+ 7	103	12,145
+ 6	1	92.02	+ 6	88	12,175
+ 5	1	91.80	+ 5	74	12,205
+ 4	0	91.58	+ 4	59	12,235
+ 3	0	91.36	+ 3	44	12,265
+ 2	0	91.14	+ 2	29	12,294
+ 1	0	90.92	+ 1	15	12,324
				0	12,354
0	0	90.70	0	0	12,429
				0	12,504
- 1	(0)	90.43	- 1	(15)	12,534
- 2	(0)	90.16	- 2	(29)	12,564
- 3	(0)	89.89	- 3	(44)	12,593
- 4	(0)	89.62	- 4	(59)	12,623
- 5	(1)	89.35	- 5	(74)	12,653
- 6	(1)	89.08	- 6	(88)	12,683
- 7	(1)	88.81	- 7	(103)	12,713
- 8	(1)	88.54	- 8	(118)	12,742
- 9	(1)	88.27	- 9	(132)	12,772
- 10	(1)	88.00	- 10	(147)	12,802
Weighting Factor:		0.000	Weighting Factor:		0.025

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2018 - December 2018

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	83	93.70	+ 10	3,095	6,724
+ 9	75	93.65	+ 9	2,786	6,737
+ 8	66	93.60	+ 8	2,476	6,751
+ 7	58	93.55	+ 7	2,167	6,764
+ 6	50	93.50	+ 6	1,857	6,777
+ 5	42	93.45	+ 5	1,548	6,791
+ 4	33	93.40	+ 4	1,238	6,804
+ 3	25	93.35	+ 3	929	6,817
+ 2	17	93.30	+ 2	619	6,830
+ 1	8	93.25	+ 1	310	6,844
				0	6,857
0	0	93.20	0	0	6,932
				0	7,007
- 1	(1)	93.11	- 1	(310)	7,020
- 2	(2)	93.02	- 2	(619)	7,034
- 3	(3)	92.93	- 3	(929)	7,047
- 4	(4)	92.84	- 4	(1,238)	7,060
- 5	(6)	92.75	- 5	(1,548)	7,074
- 6	(7)	92.66	- 6	(1,857)	7,087
- 7	(8)	92.57	- 7	(2,167)	7,100
- 8	(9)	92.48	- 8	(2,476)	7,113
- 9	(10)	92.39	- 9	(2,786)	7,127
- 10	(11)	92.30	- 10	(3,095)	7,140
Weighting Factor:		0.014	Weighting Factor:		0.516

Issued by: Gulf Power Company

GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2018 - December 2018

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss ($000)
Scherer 3	0.2	97.2	98.1	96.0	$12	($10)	94.2	($10)
Crist 7	0.1	82.1	83.4	80.6	$3	($15)	74.5	($15)
Daniel 1	0.0	82.2	84.5	81.7	$0	$0	73.9	$0
Daniel 2	0.0	90.7	92.9	88.0	$1	($1)	82.3	($1)
Smith 3	1.4	93.2	93.7	92.3	$83	($11)	86.7	($11)
Total:	2.0							

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Max BTU/KWH	ANOHR Range Min BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss ($000)
Scherer 3	34.8	10,495	77.6	10,810	10,180	$2,089	($2,089)	10,553	$0
Crist 7	8.3	10,503	71.9	10,818	10,188	$500	($500)	10,532	$0
Daniel 1	1.1	12,205	29.7	12,571	11,839	$65	($65)	12,059	$16
Daniel 2	2.5	12,429	30.5	12,802	12,056	$147	($147)	12,155	$98
Smith 3	51.6	6,932	91.0	7,140	6,724	$3,095	($3,095)	6,905	$0
Total:	98.3								

Issued by: Gulf Power Company

Actual Unit Performance Data

Gulf Power Company

Period of: January 2018 - December 2018

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Scherer 3	93.8	0.4	94.2
Crist 7	64.5	10.0	74.5
Daniel 1	68.7	5.2	73.9
Daniel 2	84.4	-2.1	82.3
Smith 3	87.9	-1.2	86.7

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Scherer 3	10,734	-181	10,553
Crist 7	10,480	52	10,532
Daniel 1	11,325	734	12,059
Daniel 2	11,292	863	12,155
Smith 3	6,933	-28	6,905

* 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 2018 - December 2018

	SCHERER 3	Jan '18	Feb '18	Mar '18	Apr '18	May '18	Jun '18	
1.	EAF (%)	99.6	100.0	93.0	99.9	68.6	100.0	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	741.2	672.0	691.1	720.0	523.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	2.8	0.0	51.9	0.0	221.0	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	2.8	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	51.9	0.0	221.0	0.0	
9.	PFOH	0.4	0.0	0.0	1.7	26.2	0.0	
10.	LR pf (MW)	860.0	0.0	0.0	359.0	420.1	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	4,429,003	2,667,757	2,789,037	3,586,414	3,114,775	4,368,874	
15.	Net Gen (MWH)	419,053	238,089	255,178	327,050	291,198	399,280	
16.	ANOHR (Btu/KWH)	10,569	11,205	10,930	10,966	10,696	10,942	
17.	NOF %	65.4	41.0	42.7	52.5	64.4	64.1	
18.	NPC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	
19.	ANOHR Equation	10^6 / AKW * [532.42 - 83.71 * MAR + 152.71 * MAY] + 9,692						

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2018 - December 2018

	SCHERER 3	Jul '18	Aug '18	Sep '18	Oct '18	Nov '18	Dec '18	Total
1.	EAF (%)	100.0	99.7	100.0	80.6	100.0	86.2	93.8
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	744.0	720.0	599.5	721.0	659.1	8254.8
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	0.0	144.5	0.0	84.9	505.2
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	0.0	144.5	0.0	3.4	150.7
8.	MOH	0.0	0.0	0.0	0.0	0.0	81.6	354.5
9.	PFOH	0.0	0.5	0.0	0.0	0.0	27.9	56.7
10.	LR pf (MW)	0.0	111.0	0.0	0.0	0.0	548.8	482.3
11.	PMOH	0.0	5.0	0.0	0.0	0.0	0.0	5.0
12.	LR pm (MW)	0.0	367.0	0.0	0.0	0.0	0.0	367.0
13.	NSC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	865.0
14.	Oper MBtu	4,836,740	4,769,884	5,308,889	4,043,039	4,880,980	3,405,700	48,201,092
15.	Net Gen (MWH)	446,378	448,366	505,151	378,360	470,036	312,419	4,490,558
16.	ANOHR (Btu/KWH)	10,836	10,638	10,510	10,686	10,384	10,901	10,734
17.	NOF %	69.4	69.7	81.1	73.0	75.4	54.8	62.9
18.	NPC (MW)	865.0	865.0	865.0	865.0	865.0	865.0	865.0

19.	ANOHR Equation	10^6 / AKW * [532.42 - 83.71 * MAR + 152.71 * MAY] + 9,692

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2018 - December 2018

	CRIST 7	Jan '18	Feb '18	Mar '18	Apr '18	May '18	Jun '18	
1.	EAF (%)	47.4	39.3	0.0	0.0	70.8	78.0	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	352.7	120.1	0.0	0.0	576.8	612.5	
4.	RSH	0.0	144.0	0.0	0.0	0.0	0.0	
5.	UH	391.3	407.9	743.0	720.0	167.3	107.5	
6.	POH	0.0	0.0	695.0	720.0	16.4	0.0	
7.	FOH	0.0	0.0	0.0	0.0	114.6	0.8	
8.	MOH	391.3	407.9	48.0	0.0	36.3	106.7	
9.	PFOH	0.0	0.0	0.0	0.0	125.1	75.9	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	190.0	190.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	51.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	190.0	
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	
14.	Oper MBtu	1,440,019	407,093	0	0	1,847,512	2,113,389	
15.	Net Gen (MWH)	139,399	39,765	0	0	175,139	196,649	
16.	ANOHR (Btu/KWH)	10,330	10,237	0	0	10,549	10,747	
17.	NOF %	83.2	69.7	0.0	0.0	63.9	67.6	
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	

19.	ANOHR Equation	10^6 / AKW * [330.88 - 62.20 * JAN - 68.36 * FEB - 48.28 * MAR - 28.26 * NOV] + 9,711 - 0.00043 * LSRF / AKW

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2018 - December 2018

	CRIST 7	Jul '18	Aug '18	Sep '18	Oct '18	Nov '18	Dec '18	Total
1.	EAF (%)	87.1	77.1	72.3	100.0	99.3	100.0	64.5
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	648.1	573.7	520.4	744.0	715.9	744.0	5608.1
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	144.0
5.	UH	95.9	170.4	199.6	0.0	5.1	0.0	3008.0
6.	POH	0.0	170.4	195.0	0.0	0.0	0.0	1796.8
7.	FOH	31.5	0.0	4.6	0.0	5.1	0.0	156.6
8.	MOH	64.4	0.0	0.0	0.0	0.0	0.0	1054.6
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	200.9
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	190.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	51.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	190.0
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0
14.	Oper MBtu	2,357,722	2,044,592	2,172,295	2,818,353	2,725,871	2,541,197	20,468,043
15.	Net Gen (MWH)	225,834	198,238	202,094	276,811	263,549	235,496	1,952,974
16.	ANOHR (Btu/KWH)	10,440	10,314	10,749	10,182	10,343	10,791	10,480
17.	NOF %	73.4	72.8	81.8	78.3	77.5	66.6	73.3
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0

19.	ANOHR Equation	10^6 / AKW * [330.88 - 62.20 * JAN - 68.36 * FEB - 48.28 * MAR - 28.26 * NOV] + 9,711 - 0.00043 * LSRF / AKW

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2018 - December 2018

	DANIEL 1	Jan '18	Feb '18	Mar '18	Apr '18	May '18	Jun '18	
1.	EAF (%)	85.6	100.0	0.0	14.1	71.7	83.9	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	740.6	140.4	0.0	109.4	595.6	713.5	
4.	RSH	0.0	531.6	0.0	0.0	0.0	0.0	
5.	UH	3.4	0.0	743.0	610.6	148.4	6.6	
6.	POH	0.0	0.0	743.0	610.6	0.0	0.0	
7.	FOH	3.4	0.0	0.0	0.0	2.3	6.6	
8.	MOH	0.0	0.0	0.0	0.0	146.2	0.0	
9.	PFOH	575.9	0.0	0.0	0.0	12.5	19.6	
10.	LR pf (MW)	89.5	0.0	0.0	0.0	86.0	80.5	
11.	PMOH	1.3	0.0	0.0	109.4	511.6	625.2	
12.	LR pm (MW)	344.0	0.0	0.0	36.0	59.0	85.1	
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
14.	Oper MBtu	1,577,643	258,626	0	260,095	1,293,373	1,680,396	
15.	Net Gen (MWH)	139,431	24,250	0	20,350	112,543	143,173	
16.	ANOHR (Btu/KWH)	11,315	10,665	0	12,781	11,492	11,737	
17.	NOF %	37.5	34.4	0.0	37.0	37.6	40.0	
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	

19.	ANOHR Equation	10^6 / AKW * [481.17 + 92.71 * JAN + 85.98 * MAY] + 8,753 + 0.00100 * LSRF / AKW

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2018 - December 2018

	DANIEL 1	Jul '18	Aug '18	Sep '18	Oct '18	Nov '18	Dec '18	Total
1.	EAF (%)	82.7	82.8	76.3	64.3	82.0	83.6	68.7
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	488.4	677.3	556.5	696.5	499.3	5961.4
4.	RSH	0.0	237.5	0.0	75.4	0.0	203.7	1048.1
5.	UH	0.0	18.2	42.7	112.2	24.6	41.1	1750.6
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1353.6
7.	FOH	0.0	0.0	0.0	32.9	0.0	0.0	45.1
8.	MOH	0.0	18.2	42.7	79.3	24.6	41.1	352.0
9.	PFOH	9.4	501.7	753.9	440.3	14.2	0.0	2327.4
10.	LR pf (MW)	86.0	73.7	82.8	79.8	91.0	0.0	82.0
11.	PMOH	744.0	209.9	578.7	599.5	622.1	513.4	4515.1
12.	LR pm (MW)	86.0	85.8	2.8	70.2	82.7	79.1	67.7
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
14.	Oper MBtu	1,382,155	934,717	1,587,972	1,331,143	1,497,964	1,058,692	12,862,776
15.	Net Gen (MWH)	114,932	80,281	141,790	125,646	134,181	99,225	1,135,802
16.	ANOHR (Btu/KWH)	12,026	11,643	11,199	10,594	11,164	10,670	11,325
17.	NOF %	30.8	32.7	41.7	45.0	38.4	39.6	38.0
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0

19.	ANOHR Equation	10^6 / AKW * [481.17 + 92.71 * JAN + 85.98 * MAY] + 8,753 + 0.00100 * LSRF / AKW

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2018 - December 2018

	DANIEL 2	Jan '18	Feb '18	Mar '18	Apr '18	May '18	Jun '18	
1.	EAF (%)	98.6	100.0	74.2	93.0	93.8	88.5	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	535.4	166.3	65.3	142.6	744.0	707.8	
4.	RSH	208.6	505.7	485.7	544.8	0.0	0.0	
5.	UH	0.0	0.0	192.0	32.7	0.0	12.2	
6.	POH	0.0	0.0	192.0	24.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	8.7	0.0	12.2	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	24.7	0.0	0.0	0.0	0.0	13.1	
10.	LR pf (MW)	211.7	0.0	0.0	0.0	0.0	100.9	
11.	PMOH	0.0	0.0	0.0	250.3	645.0	611.0	
12.	LR pm (MW)	0.0	0.0	0.0	36.0	36.0	55.8	
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	
14.	Oper MBtu	1,360,872	310,868	161,298	299,595	1,786,874	1,686,477	
15.	Net Gen (MWH)	121,522	30,438	14,854	24,283	158,163	151,347	
16.	ANOHR (Btu/KWH)	11,199	10,213	10,859	12,338	11,298	11,143	
17.	NOF %	45.2	36.5	45.3	33.9	42.3	42.6	
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	

19.	ANOHR Equation	10^6 / AKW * [606.70 + 74.51 * JAN - 120.51 * FEB + 58.65 * MAY + 44.01 * JUN - 44.62 * SEP - 81.23 * OCT - 185.41 * NOV] + 8,600

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2018 - December 2018

	DANIEL 2	Jul '18	Aug '18	Sep '18	Oct '18	Nov '18	Dec '18	Total
1.	EAF (%)	83.5	82.0	71.9	60.2	84.6	83.7	84.4
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	708.3	693.8	625.0	622.6	523.4	6278.5
4.	RSH	0.0	0.0	0.0	24.0	98.4	220.6	2087.8
5.	UH	0.0	35.7	26.2	95.0	0.0	0.0	393.8
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	216.0
7.	FOH	0.0	1.8	0.0	0.0	0.0	0.0	22.7
8.	MOH	0.0	33.9	26.2	95.0	0.0	0.0	155.1
9.	PFOH	234.1	417.5	657.2	666.4	6.1	162.2	2181.2
10.	LR pf (MW)	69.1	68.4	81.4	87.6	77.6	100.4	82.5
11.	PMOH	529.5	344.1	578.9	538.6	644.2	477.7	4619.3
12.	LR pm (MW)	86.0	60.5	60.5	79.4	86.0	93.4	67.2
13.	NSC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0
14.	Oper MBtu	1,459,198	1,490,708	1,638,626	1,441,977	1,364,037	1,022,965	14,023,496
15.	Net Gen (MWH)	124,437	129,256	146,208	132,536	118,313	90,537	1,241,894
16.	ANOHR (Btu/KWH)	11,726	11,533	11,208	10,880	11,529	11,299	11,292
17.	NOF %	33.3	36.4	42.0	42.2	37.9	34.5	39.4
18.	NPC (MW)	502.0	502.0	502.0	502.0	502.0	502.0	502.0

19.	ANOHR Equation	10^6 / AKW * [606.70 + 74.51 * JAN - 120.51 * FEB + 58.65 * MAY + 44.01 * JUN - 44.62 * SEP - 81.23 * OCT - 185.41 * NOV] + 8,600

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2018 - December 2018

	SMITH 3	Jan '18	Feb '18	Mar '18	Apr '18	May '18	Jun '18	
1.	EAF (%)	98.8	99.8	96.5	100.0	63.1	100.0	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	744.0	672.0	725.5	720.0	512.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	0.0	17.5	0.0	232.0	0.0	
6.	POH	0.0	0.0	0.0	0.0	232.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	17.5	0.0	0.0	0.0	
9.	PFOH	3.1	3.3	0.0	0.0	0.0	0.8	
10.	LR pf (MW)	150.3	276.0	0.0	0.0	0.0	250.0	
11.	PMOH	17.5	0.0	18.2	0.0	98.1	0.0	
12.	LR pm (MW)	276.0	0.0	276.0	0.0	250.0	0.0	
13.	NSC (MW)	605.0	605.0	579.0	579.0	579.0	577.0	
14.	Oper MBtu	2,698,322	2,236,889	2,507,998	2,566,410	1,615,364	2,484,766	
15.	Net Gen (MWH)	387,087	324,932	362,844	382,271	234,509	352,820	
16.	ANOHR (Btu/KWH)	6,971	6,884	6,912	6,714	6,888	7,043	
17.	NOF %	86.0	79.9	86.4	91.7	79.1	84.9	
18.	NPC (MW)	605.0	605.0	579.0	579.0	579.0	577.0	

19.	ANOHR Equation	10^6 / AKW * [144.47 + 12.50 * APR - 81.62 * OCT] + 6,675

Issued by: Gulf Power Company

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2018 - December 2018

	SMITH 3	Jul '18	Aug '18	Sep '18	Oct '18	Nov '18	Dec '18	Total
1.	EAF (%)	100.0	99.9	98.0	28.1	78.4	93.9	87.9
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	744.0	720.0	209.1	682.3	744.0	7936.9
4.	RSH	0.0	0.0	0.0	0.0	3.8	0.0	3.8
5.	UH	0.0	0.0	0.0	534.9	35.0	0.0	819.4
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	232.0
7.	FOH	0.0	0.0	0.0	534.9	35.0	0.0	569.8
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	17.5
9.	PFOH	0.0	2.1	7.8	0.0	249.9	69.8	336.9
10.	LR pf (MW)	0.0	158.8	247.2	0.0	276.0	276.0	273.4
11.	PMOH	0.0	0.0	25.6	0.0	3.8	30.7	193.9
12.	LR pm (MW)	0.0	0.0	250.0	0.0	275.9	266.6	257.9
13.	NSC (MW)	577.0	577.0	577.0	579.0	579.0	605.0	584.8
14.	Oper MBtu	2,654,277	2,720,197	2,627,729	778,079	2,054,343	2,257,054	27,201,429
15.	Net Gen (MWH)	392,225	384,575	375,931	113,598	278,860	333,935	3,923,587
16.	ANOHR (Btu/KWH)	6,767	7,073	6,990	6,849	7,367	6,759	6,933
17.	NOF %	91.4	89.6	90.5	93.8	70.6	74.2	84.5
18.	NPC (MW)	577.0	577.0	577.0	579.0	579.0	605.0	584.8

19.	ANOHR Equation	10^6 / AKW * [144.47 + 12.50 * APR - 81.62 * OCT] + 6,675

Issued by: Gulf Power Company

Planned Outage Schedules (Actual)

Period of: January 2018 - December 2018

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.

EXHIBIT TO THE TESTIMONY OF

C. L. NICHOLSON

IN FPSC DOCKET 20190001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 60
PARTY: GULF POWER – (DIRECT)
DESCRIPTION: C. L. Nicholson CLN-2

I. DETERMINATION OF HEAT RATE TARGETS

Target Heat Rate Equations

Scherer 3 ANOHR = 10^6 / AKW * [606.47 - 82.01 * FEB - 83.21 * MAR + 61.69 * APR + 58.15 * JUN + 70.05 * JUL + 82.11 * SEP

+ 9,540

Crist 7 ANOHR = 10^6 / AKW * [472.40 - 98.31 * JAN - 105.00 * FEB - 75.12 * MAR - 128.98 * APR - 86.23 * MAY

+ 9,255

Daniel 1 ANOHR = 10^6 / AKW * [513.64 + 53.71 * JAN + 90.24 * MAR - 77.10 * OCT - 78.86 * NOV]

+ 8,476 + 0.00192 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * [398.23 - 174.36 * FEB - 127.75 * MAR - 64.08 * MAY + 49.83 * JUL]

+ 9,428

Smith 3 ANOHR = 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

Where:

ANOHR = Average Net Operating Heat Rate, BTU/KWH
AKW = Average Kilowatt Load, KW
LSRF = Load Square Range Factor, KW^2
BTU/LB = Coal Burned Average Heat Content, BTU/LB
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

WEEKLY UNIT OPERATING

DATA USED TO DEVELOP

TARGET HEAT RATE EQUATIONS

Data Base for SCHERER 3 Target Heat Rate Equation

HtRt	HR	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10464	168	622.70	452004	0	0	0	0	0	0	1	0	0	0	0	0	2016	JUL
10463	168	649.67	481799	0	0	0	0	0	0	1	0	0	0	0	0	2016	
10510	168	688.96	527888	0	0	0	0	0	0	1	0	0	0	0	0	2016	
10569	168	645.39	477569	0	0	0	0	0	0	1	0	0	0	0	0	2016	
10467	168	594.55	418359	0	0	0	0	0	0	0	1	0	0	0	0	2016	
10397	168	630.88	455151	0	0	0	0	0	0	0	1	0	0	0	0	2016	
10943	168	611.38	434091	0	0	0	0	0	0	0	1	0	0	0	0	2016	
10404	168	589.31	410942	0	0	0	0	0	0	0	1	0	0	0	0	2016	
10481	168	596.20	420400	0	0	0	0	0	0	0	1	0	0	0	0	2016	
10858	168	499.38	299985	0	0	0	0	0	0	0	0	1	0	0	0	2016	
10903	168	564.77	373119	0	0	0	0	0	0	0	0	1	0	0	0	2016	
10668	168	605.58	425357	0	0	0	0	0	0	0	0	1	0	0	0	2016	
10724	168	553.11	361242	0	0	0	0	0	0	0	0	1	0	0	0	2016	
10607	168	481.00	275758	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10986	168	439.63	225362	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10473	168	550.80	353989	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10891	168	432.07	215026	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10630	168	520.23	311013	0	0	0	0	0	0	0	0	0	1	0	0	2016	
11091	168	374.44	163179	0	0	0	0	0	0	0	0	0	0	1	0	2016	
11178	24	372.50	20952	0	0	0	0	0	0	0	0	0	0	1	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2016	
10869	99	385.20	104700	0	0	0	0	0	0	0	0	0	0	1	1	2016	
10293	168	498.59	289485	0	0	0	0	0	0	0	0	0	0	0	0	2016	
10024	168	668.42	496633	0	0	0	0	0	0	0	0	0	0	0	0	2016	
10208	168	557.81	353398	0	0	0	0	0	0	0	0	0	0	0	0	2016	
11030	168	324.56	108963	0	0	0	0	0	0	0	0	0	0	0	0	2016	
10810	168	502.96	294419	1	0	0	0	0	0	0	0	0	0	0	0	2017	JAN
10692	61	633.20	183594	1	0	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2017	
12011	61	310.93	47121	1	0	0	0	0	0	0	0	0	0	0	1	2017	
11005	168	327.92	112314	0	1	0	0	0	0	0	0	0	0	0	0	2017	
10640	168	367.57	148123	0	1	0	0	0	0	0	0	0	0	0	0	2017	
10399	135	438.64	200293	0	1	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2017	
11207	88	369.89	85109	0	0	1	0	0	0	0	0	0	0	0	1	2017	
10422	167	575.50	382039	0	0	1	0	0	0	0	0	0	0	0	0	2017	
10518	143	500.85	243957	0	0	1	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
10752	54	598.91	181046	0	0	0	0	1	0	0	0	0	0	0	2	2017	
11086	168	458.18	260051	0	0	0	0	1	0	0	0	0	0	0	0	2017	
10725	168	546.34	356999	0	0	0	0	1	0	0	0	0	0	0	0	2017	
10835	158	473.81	267075	0	0	0	0	0	1	0	0	0	0	0	0	2017	
10461	168	591.22	414059	0	0	0	0	0	1	0	0	0	0	0	0	2017	
10722	168	497.67	303975	0	0	0	0	0	1	0	0	0	0	0	0	2017	
10825	144	483.65	291900	0	0	0	0	0	1	0	0	0	0	0	0	2017	
10610	168	572.56	394246	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL

Data Base for SCHERER 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10540	168	624.90	458929	0	0	0	0	0	0	1	0	0	0	0	0	2017	
10560	168	628.99	462900	0	0	0	0	0	0	1	0	0	0	0	0	2017	
10585	146	601.40	397138	0	0	0	0	0	0	1	0	0	0	0	0	2017	
10579	168	573.29	390209	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10574	168	533.36	343400	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10446	168	663.76	498544	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10300	168	622.20	453669	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10444	168	539.07	346204	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10861	168	501.85	307597	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11309	168	412.66	207138	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10594	168	671.29	507350	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10659	168	628.32	456310	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10948	168	471.89	270302	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10746	168	581.77	394817	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10800	168	479.40	271563	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11401	168	371.80	155290	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11022	168	390.80	178361	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10253	168	531.51	319892	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10448	168	475.33	256096	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11065	168	332.02	117386	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11736	94	356.05	81551	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10786	66	521.97	136732	0	0	0	0	0	0	0	0	0	0	0	1	2017	
10828	168	483.17	285715	0	0	0	0	0	0	0	0	0	0	0	0	2017	
10802	71	501.66	125575	0	0	0	0	0	0	0	0	0	0	0	0	2017	
11338	139	394.18	157312	0	0	0	0	0	0	0	0	0	0	0	1	2017	
10296	165	831.41	701486	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10703	168	518.92	337125	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10576	168	549.14	365050	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10850	168	409.38	198042	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10850	168	440.92	235529	0	1	0	0	0	0	0	0	0	0	0	0	2018	
11136	168	347.60	132949	0	1	0	0	0	0	0	0	0	0	0	0	2018	
11471	168	309.68	97260	0	1	0	0	0	0	0	0	0	0	0	0	2018	
11306	168	345.13	138484	0	1	0	0	0	0	0	0	0	0	0	0	2018	
11017	120	424.55	162491	0	0	1	0	0	0	0	0	0	0	0	0	2018	
11102	163	339.98	122725	0	0	1	0	0	0	0	0	0	0	0	1	2018	
10848	168	370.59	157097	0	0	1	0	0	0	0	0	0	0	0	0	2018	
10876	168	360.14	147039	0	0	1	0	0	0	0	0	0	0	0	0	2018	
10998	168	372.71	161663	0	0	1	0	0	0	0	0	0	0	0	0	2018	
10811	168	467.73	261011	0	0	0	1	0	0	0	0	0	0	0	0	2018	
10626	168	556.36	360054	0	0	0	1	0	0	0	0	0	0	0	0	2018	
11147	168	421.34	205784	0	0	0	1	0	0	0	0	0	0	0	0	2018	
11308	168	400.76	183892	0	0	0	1	0	0	0	0	0	0	0	0	2018	
10845	119	490.01	209218	0	0	0	0	1	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10556	164	613.59	442514	0	0	0	0	1	0	0	0	0	0	0	1	2018	
10747	168	557.52	370465	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10908	168	525.23	330384	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10971	168	504.72	313957	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10972	168	532.90	344199	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10768	168	630.71	462274	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11023	144	548.30	365833	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10879	168	584.89	408202	0	0	0	0	0	0	1	0	0	0	0	0	2018	JUL
10817	168	596.44	420909	0	0	0	0	0	0	1	0	0	0	0	0	2018	
10808	168	613.71	438642	0	0	0	0	0	0	1	0	0	0	0	0	2018	

Data Base for SCHERER 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10850	168	597.85	424515	0	0	0	0	0	0	1	0	0	0	0	0	2018	
10767	168	583.04	402835	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10707	168	627.98	456600	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10691	168	594.28	419929	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10600	168	570.57	389647	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10519	168	642.25	475036	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10546	168	701.02	543561	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10515	168	697.92	538222	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10335	168	707.73	548644	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10563	168	731.10	577202	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10662	157	657.12	465458	0	0	0	0	0	0	0	0	0	1	0	0	2018	
11065	87	520.98	200316	0	0	0	0	0	0	0	0	0	1	0	1	2018	
10510	168	746.71	596887	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10841	157	561.25	370782	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10605	127	543.35	275153	0	0	0	0	0	0	0	0	0	1	0	1	2018	
10539	168	572.54	386175	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10597	168	607.32	428322	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10233	168	708.19	540908	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10202	168	801.80	660266	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10514	168	686.24	518104	0	0	0	0	0	0	0	0	0	0	0	0	2018	
10686	140	541.46	306465	0	0	0	0	0	0	0	0	0	0	0	0	2018	
11362	110	325.25	76951	0	0	0	0	0	0	0	0	0	0	0	1	2018	
11668	168	301.73	91094	0	0	0	0	0	0	0	0	0	0	0	0	2018	
11445	168	315.18	102532	1	0	0	0	0	0	0	0	0	0	0	0	2019	JAN
10796	168	430.40	222437	1	0	0	0	0	0	0	0	0	0	0	0	2019	
10641	168	479.54	269709	1	0	0	0	0	0	0	0	0	0	0	0	2019	
11374	168	338.59	127434	1	0	0	0	0	0	0	0	0	0	0	0	2019	
11356	72	327.89	50300	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11169	135	474.77	222476	0	0	0	1	0	0	0	0	0	0	0	1	2019	
11515	168	352.29	135699	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11195	168	402.45	192136	0	0	0	1	0	0	0	0	0	0	0	0	2019	
10604	168	562.80	365523	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10902	168	451.23	238371	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10910	168	439.89	230139	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10794	168	534.32	344824	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10718	168	537.96	350536	0	0	0	0	1	0	0	0	0	0	0	0	2019	
11189	168	364.15	149577	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11240	131	401.60	163433	0	0	0	0	0	1	0	0	0	0	0	1	2019	
11053	168	412.73	201750	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11081	144	434.91	229195	0	0	0	0	0	1	0	0	0	0	0	0	2019	

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 7 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10471	168	347.30	135997	0	0	0	0	0	0	1	0	0	0	0	0	2016	JUL
10579	168	323.51	118984	0	0	0	0	0	0	1	0	0	0	0	0	2016	
10512	168	324.61	119648	0	0	0	0	0	0	1	0	0	0	0	0	2016	
10765	168	333.40	126683	0	0	0	0	0	0	1	0	0	0	0	0	2016	
10703	168	329.18	122299	0	0	0	0	0	0	0	1	0	0	0	0	2016	
10961	168	325.70	119952	0	0	0	0	0	0	0	1	0	0	0	0	2016	
11380	117	295.50	71273	0	0	0	0	0	0	0	1	0	0	0	0	2016	
10015	168	328.77	121809	0	0	0	0	0	0	0	1	0	0	0	0	2016	
10269	168	271.63	82270	0	0	0	0	0	0	0	0	1	0	0	0	2016	
10981	168	315.61	111387	0	0	0	0	0	0	0	0	1	0	0	0	2016	
10890	168	319.58	114900	0	0	0	0	0	0	0	0	1	0	0	0	2016	
10818	168	333.62	125227	0	0	0	0	0	0	0	0	1	0	0	0	2016	
10585	168	292.44	95407	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10927	96	292.41	52056	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10715	152	329.32	124293	0	0	0	0	0	0	0	0	0	1	0	1	2016	
10993	168	276.01	83774	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10640	26	298.27	17035	0	0	0	0	0	0	0	0	0	1	0	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2016	
11101	117	247.28	49809	0	0	0	0	0	0	0	0	0	0	0	2	2016	
11161	168	263.46	70885	0	0	0	0	0	0	0	0	0	0	0	0	2016	
10593	168	348.84	130020	1	0	0	0	0	0	0	0	0	0	0	0	2017	JAN
10381	168	320.61	114972	1	0	0	0	0	0	0	0	0	0	0	0	2017	
10543	168	287.96	91765	1	0	0	0	0	0	0	0	0	0	0	0	2017	
10798	131	241.39	53791	1	0	0	0	0	0	0	0	0	0	0	1	2017	
10741	168	251.79	66146	0	1	0	0	0	0	0	0	0	0	0	0	2017	
10770	168	251.11	66653	0	1	0	0	0	0	0	0	0	0	0	0	2017	
10869	168	236.88	59526	0	1	0	0	0	0	0	0	0	0	0	0	2017	
10713	71	251.96	29434	0	1	0	0	0	0	0	0	0	0	0	0	2017	
11050	127	240.87	49970	0	0	1	0	0	0	0	0	0	0	0	1	2017	
10493	168	277.47	84728	0	0	1	0	0	0	0	0	0	0	0	0	2017	
10076	167	350.53	134495	0	0	1	0	0	0	0	0	0	0	0	0	2017	
10304	168	311.79	107130	0	0	1	0	0	0	0	0	0	0	0	0	2017	
10271	168	308.10	106746	0	0	1	0	0	0	0	0	0	0	0	0	2017	
10257	168	284.86	90636	0	0	0	1	0	0	0	0	0	0	0	0	2017	
10265	168	333.67	123795	0	0	0	1	0	0	0	0	0	0	0	0	2017	
9746	168	429.11	186150	0	0	0	1	0	0	0	0	0	0	0	0	2017	
10406	59	334.17	45730	0	0	0	1	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
11507	29	232.83	11701	0	0	0	0	0	1	0	0	0	0	0	1	2017	
10605	168	323.51	113774	0	0	0	0	0	1	0	0	0	0	0	0	2017	
10706	49	323.06	37514	0	0	0	0	0	1	0	0	0	0	0	0	2017	
10374	92	290.28	75113	0	0	0	0	0	1	0	0	0	0	0	2	2017	
10565	168	337.15	124845	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL
10530	168	316.18	106904	0	0	0	0	0	0	1	0	0	0	0	0	2017	
10402	168	357.85	133880	0	0	0	0	0	0	1	0	0	0	0	0	2017	

Data Base for CRIST 7 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
10688	72	307.18	42538	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10470	109	343.27	91015	0	0	0	0	0	0	0	1	0	0	0	1	2017	
10745	168	373.48	145617	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10784	120	306.82	69298	0	0	0	0	0	0	0	1	0	0	0	0	2017	
10780	82	338.63	65731	0	0	0	0	0	0	0	1	0	0	0	1	2017	
10716	168	347.29	128596	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10637	168	337.30	117547	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10497	49	322.94	31897	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10694	131	370.98	118213	0	0	0	0	0	0	0	0	1	0	0	1	2017	
10651	168	343.42	125155	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10842	166	349.87	127263	0	0	0	0	0	0	0	0	0	1	0	0	2017	
9855	98	316.53	64577	0	0	0	0	0	0	0	0	0	1	0	1	2017	
10708	168	284.41	84739	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10882	82	249.59	35235	0	0	0	0	0	0	0	0	0	1	0	0	2017	
9921	72	338.96	53187	0	0	0	0	0	0	0	0	0	0	1	1	2017	
9882	168	310.49	101792	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10223	168	281.00	83366	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10130	96	277.38	46482	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11534	81	322.15	57925	0	0	0	0	0	0	0	0	0	0	0	1	2017	
11409	167	300.26	95703	0	0	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2017	
11924	118	272.11	60659	0	0	0	0	0	0	0	0	0	0	0	1	2017	
10231	168	440.12	198087	1	0	0	0	0	0	0	0	0	0	0	0	2018	JAN
10425	46	308.96	27537	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10441	80	374.80	83825	1	0	0	0	0	0	0	0	0	0	0	1	2018	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10287	154	355.23	129137	0	1	0	0	0	0	0	0	0	0	0	1	2018	
10351	24	263.46	12583	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
10793	84	279.35	50334	0	0	0	0	1	0	0	0	0	0	0	2	2018	
10331	168	352.96	133946	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10407	132	354.58	117516	0	0	0	0	1	0	0	0	0	0	0	1	2018	
10804	96	262.98	55498	0	0	0	0	1	0	0	0	0	0	0	1	2018	
10962	168	213.24	45559	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11432	60	231.70	28336	0	0	0	0	0	1	0	0	0	0	0	1	2018	
10734	168	319.64	110934	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10643	168	380.42	155449	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10615	144	344.71	129166	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10766	141	328.64	102145	0	0	0	0	0	0	1	0	0	0	0	1	2018	
10647	168	350.81	134348	0	0	0	0	0	0	1	0	0	0	0	0	2018	JUL
10758	116	358.07	99113	0	0	0	0	0	0	1	0	0	0	0	0	2018	
10015	150	355.30	127774	0	0	0	0	0	0	1	0	0	0	0	1	2018	
10068	168	340.14	126220	0	0	0	0	0	0	0	1	0	0	0	0	2018	

Data Base for CRIST 7 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
9791	168	376.65	151048	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10473	168	341.43	124783	0	0	0	0	0	0	0	1	0	0	0	0	2018	
10821	142	325.25	96631	0	0	0	0	0	0	0	1	0	0	0	0	2018	
0	0	0.00	0	0	0	0	0	0	0	0	1	0	0	0	0	2018	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2018	
11016	159	368.25	144102	0	0	0	0	0	0	0	0	1	0	0	1	2018	
10645	168	393.90	164935	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10549	168	410.24	176442	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10313	168	386.49	159371	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10081	168	398.17	168729	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10102	168	427.77	189528	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10238	168	303.49	97389	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10308	168	328.04	113931	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10408	168	351.03	128917	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10409	168	380.64	150118	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10126	168	392.41	156735	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10456	162	367.73	138208	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10634	168	380.32	147977	0	0	0	0	0	0	0	0	0	0	0	0	2018	
10626	168	376.93	148542	0	0	0	0	0	0	0	0	0	0	0	0	2018	
10934	168	273.82	78066	0	0	0	0	0	0	0	0	0	0	0	0	2018	
11171	168	245.02	60049	0	0	0	0	0	0	0	0	0	0	0	0	2018	
10885	168	246.56	60868	1	0	0	0	0	0	0	0	0	0	0	0	2019	JAN
10766	168	249.58	62698	1	0	0	0	0	0	0	0	0	0	0	0	2019	
10450	82	272.49	42049	1	0	0	0	0	0	0	0	0	0	0	0	2019	
9999	126	357.31	100897	1	0	0	0	0	0	0	0	0	0	0	1	2019	
10173	168	360.75	136522	0	1	0	0	0	0	0	0	0	0	0	0	2019	
10808	109	297.64	68403	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
10761	114	292.18	65393	0	0	1	0	0	0	0	0	0	0	0	1	2019	
10678	167	325.31	113474	0	0	1	0	0	0	0	0	0	0	0	0	2019	
10982	168	274.74	77125	0	0	1	0	0	0	0	0	0	0	0	0	2019	
11235	168	272.86	75333	0	0	1	0	0	0	0	0	0	0	0	0	2019	
10517	168	307.32	101130	0	0	1	0	0	0	0	0	0	0	0	0	2019	
10493	168	288.85	90509	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11011	72	275.89	34044	0	0	0	1	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2019	
10933	168	297.08	94607	0	0	0	0	1	0	0	0	0	0	0	0	2019	
9973	168	261.18	69440	0	0	0	0	1	0	0	0	0	0	0	0	2019	
11003	168	291.64	89583	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10772	168	322.23	111241	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10114	168	327.18	115238	0	0	0	0	1	0	0	0	0	0	0	0	2019	
11132	168	264.57	72299	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11363	168	252.71	64529	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11287	165	294.91	93138	0	0	0	0	0	1	0	0	0	0	0	0	2019	
10585	92	294.85	61088	0	0	0	0	0	1	0	0	0	0	0	0	2019	

Data Base for CRIST 7 Target Heat Rate Equation

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 1 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
11118	168	263.56	89837	0	0	0	0	0	0	1	0	0	0	0	0	2016	JUL
11588	160	232.93	71855	0	0	0	0	0	0	1	0	0	0	0	0	2016	
11868	168	235.20	74390	0	0	0	0	0	0	1	0	0	0	0	0	2016	
11828	168	252.13	81555	0	0	0	0	0	0	1	0	0	0	0	0	2016	
11988	168	193.86	46292	0	0	0	0	0	0	0	1	0	0	0	0	2016	
11725	168	197.71	49002	0	0	0	0	0	0	0	1	0	0	0	0	2016	
12544	168	184.10	39730	0	0	0	0	0	0	0	1	0	0	0	0	2016	
11862	168	187.92	42721	0	0	0	0	0	0	0	1	0	0	0	0	2016	
11050	168	221.76	63070	0	0	0	0	0	0	0	1	0	0	0	0	2016	
12552	167	140.69	20218	0	0	0	0	0	0	0	0	1	0	0	0	2016	
11535	139	170.55	28662	0	0	0	0	0	0	0	0	1	0	0	0	2016	
11100	87	303.95	68414	0	0	0	0	0	0	0	0	1	0	0	1	2016	
11740	168	203.36	54407	0	0	0	0	0	0	0	0	1	0	0	0	2016	
11009	168	199.39	52731	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10979	47	202.53	14558	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10635	96	257.39	49683	0	0	0	0	0	0	0	0	0	1	0	1	2016	
11451	168	194.70	51799	0	0	0	0	0	0	0	0	0	0	1	0	2016	
12148	168	145.23	22445	0	0	0	0	0	0	0	0	0	0	1	0	2016	
11752	168	149.13	24946	0	0	0	0	0	0	0	0	0	0	1	0	2016	
11537	168	160.46	30721	0	0	0	0	0	0	0	0	0	0	1	0	2016	
12354	168	143.68	21303	0	0	0	0	0	0	0	0	0	0	0	0	2016	
11937	92	170.41	18056	0	0	0	0	0	0	0	0	0	0	0	1	2016	
12661	168	154.15	26947	0	0	0	0	0	0	0	0	0	0	0	0	2016	
12360	168	141.19	20107	0	0	0	0	0	0	0	0	0	0	0	0	2016	
11160	168	367.01	154806	1	0	0	0	0	0	0	0	0	0	0	0	2017	JAN
11062	168	367.61	146031	1	0	0	0	0	0	0	0	0	0	0	0	2017	
10468	168	397.02	160489	1	0	0	0	0	0	0	0	0	0	0	0	2017	
11538	168	263.78	73013	1	0	0	0	0	0	0	0	0	0	0	0	2017	
10899	48	298.48	27018	0	1	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2017	
12837	162	152.48	24431	0	0	1	0	0	0	0	0	0	0	0	0	2017	
12832	168	136.79	18729	0	0	1	0	0	0	0	0	0	0	0	0	2017	
12334	168	150.46	24577	0	0	1	0	0	0	0	0	0	0	0	0	2017	
12150	168	154.29	26763	0	0	0	1	0	0	0	0	0	0	0	0	2017	
11964	168	158.79	28947	0	0	0	1	0	0	0	0	0	0	0	0	2017	
13052	168	172.48	36308	0	0	0	1	0	0	0	0	0	0	0	0	2017	
12252	24	136.17	2657	0	0	0	0	1	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
10653	154	284.44	92805	0	0	0	0	1	0	0	0	0	0	0	1	2017	
11081	168	323.01	129162	0	0	0	0	1	0	0	0	0	0	0	0	2017	
12748	168	143.83	21859	0	0	0	0	1	0	0	0	0	0	0	0	2017	
12034	168	157.98	30523	0	0	0	0	0	1	0	0	0	0	0	0	2017	
11778	164	138.94	19839	0	0	0	0	0	1	0	0	0	0	0	0	2017	
12779	168	152.42	26296	0	0	0	0	0	1	0	0	0	0	0	0	2017	
12068	144	152.44	28764	0	0	0	0	0	1	0	0	0	0	0	0	2017	
12333	168	154.28	25121	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL
12122	99	142.32	14220	0	0	0	0	0	0	1	0	0	0	0	1	2017	
11076	168	197.22	50243	0	0	0	0	0	0	1	0	0	0	0	0	2017	
12232	168	159.79	27801	0	0	0	0	0	0	1	0	0	0	0	0	2017	
12049	163	161.87	32718	0	0	0	0	0	0	0	1	0	0	0	0	2017	

Data Base for DANIEL 1 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
12120	168	149.31	23920	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11580	168	175.78	34362	0	0	0	0	0	0	0	1	0	0	0	0	2017	
12075	168	157.60	26806	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11934	168	155.08	29376	0	0	0	0	0	0	0	1	0	0	0	0	2017	
12190	168	146.00	22683	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11661	168	158.71	31082	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11347	168	181.28	36988	0	0	0	0	0	0	0	0	1	0	0	0	2017	
12024	168	163.50	29534	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11212	168	206.05	54021	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11793	168	177.04	40565	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11446	168	193.79	48490	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11552	168	174.27	35830	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11440	168	186.18	43268	0	0	0	0	0	0	0	0	0	1	0	0	2017	
10459	168	273.54	84948	0	0	0	0	0	0	0	0	0	0	1	0	2017	
10738	168	213.07	63616	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11657	168	139.64	19722	0	0	0	0	0	0	0	0	0	0	1	0	2017	
12045	119	133.07	12713	0	0	0	0	0	0	0	0	0	0	1	0	2017	
13645	56	147.04	9314	0	0	0	0	0	0	0	0	0	0	0	1	2017	
12520	168	160.57	26156	0	0	0	0	0	0	0	0	0	0	0	0	2017	
12696	11	149.27	3381	0	0	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2017	
10940	168	188.90	38819	1	0	0	0	0	0	0	0	0	0	0	0	2018	JAN
11510	168	187.68	36913	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10667	165	207.21	46811	1	0	0	0	0	0	0	0	0	0	0	0	2018	
12546	166	171.64	29783	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10711	168	180.20	33203	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
13160	85	165.15	17113	0	0	0	1	0	0	0	0	0	0	0	1	2018	
12029	166	184.15	43175	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11419	168	185.63	40293	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10822	48	188.48	11706	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11693	141	194.39	35130	0	0	0	0	1	0	0	0	0	0	0	1	2018	
11298	168	206.64	44532	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11861	162	178.49	37661	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11737	168	207.05	44553	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11241	168	249.68	65612	0	0	0	0	0	1	0	0	0	0	0	0	2018	
12449	144	162.89	28731	0	0	0	0	0	1	0	0	0	0	0	0	2018	
12118	168	151.79	24587	0	0	0	0	0	0	1	0	0	0	0	0	2018	JUL
11990	168	161.01	28252	0	0	0	0	0	0	1	0	0	0	0	0	2018	
11779	168	163.07	30807	0	0	0	0	0	0	1	0	0	0	0	0	2018	
12378	168	142.65	20765	0	0	0	0	0	0	1	0	0	0	0	0	2018	
11841	168	148.36	23062	0	0	0	0	0	0	0	1	0	0	0	0	2018	
11364	168	182.65	38044	0	0	0	0	0	0	0	1	0	0	0	0	2018	
12212	15	139.53	2946	0	0	0	0	0	0	0	1	0	0	0	0	2018	

Data Base for DANIEL 1 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
12120	65	163.31	12845	0	0	0	0	0	0	0	1	0	0	0	1	2018	
11589	168	160.54	27634	0	0	0	0	0	0	0	1	0	0	0	0	2018	
12132	168	169.49	30007	0	0	0	0	0	0	0	0	1	0	0	0	2018	
11557	168	198.58	40551	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10562	168	240.04	59346	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10748	126	238.63	47684	0	0	0	0	0	0	0	0	1	0	0	1	2018	
9894	135	281.04	72586	0	0	0	0	0	0	0	0	0	1	0	1	2018	
10212	142	293.82	76040	0	0	0	0	0	0	0	0	0	1	0	0	2018	
11047	97	206.07	29325	0	0	0	0	0	0	0	0	0	1	0	1	2018	
11893	111	146.36	15474	0	0	0	0	0	0	0	0	0	1	0	1	2018	
11693	168	160.30	25818	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10881	168	198.36	42456	0	0	0	0	0	0	0	0	0	1	0	0	2018	
12161	168	152.08	24248	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10385	168	211.79	48435	0	0	0	0	0	0	0	0	0	0	0	0	2018	
10448	147	228.07	53859	0	0	0	0	0	0	0	0	0	0	0	0	2018	
11615	109	155.94	18635	0	0	0	0	0	0	0	0	0	0	0	1	2018	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2019	JAN
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2019	
13566	46	139.54	5834	1	0	0	0	0	0	0	0	0	0	0	1	2019	
12500	168	169.45	30179	1	0	0	0	0	0	0	0	0	0	0	0	2019	
10777	117	173.86	21724	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2019	
12261	18	221.89	7912	0	0	1	0	0	0	0	0	0	0	0	1	2019	
12098	145	187.89	33473	0	0	1	0	0	0	0	0	0	0	0	0	2019	
11001	168	193.84	39273	0	0	0	1	0	0	0	0	0	0	0	0	2019	
10940	168	212.03	47104	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11564	168	189.65	37040	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11521	168	190.25	37373	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11471	168	215.40	50040	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10742	71	186.13	15250	0	0	0	0	1	0	0	0	0	0	0	0	2019	
11100	116	223.09	38697	0	0	0	0	1	0	0	0	0	0	0	1	2019	
10977	168	225.67	55082	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10548	168	248.63	70182	0	0	0	0	1	0	0	0	0	0	0	0	2019	
11216	95	184.41	20164	0	0	0	0	0	1	0	0	0	0	0	0	2019	
12077	19	179.74	5382	0	0	0	0	0	1	0	0	0	0	0	1	2019	
11288	168	216.12	52758	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11370	144	197.44	41705	0	0	0	0	0	1	0	0	0	0	0	0	2019	

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 2 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
11403	168	242.36	77372	0	0	0	0	0	0	1	0	0	0	0	0	2016	JUL
11409	163	271.05	97614	0	0	0	0	0	0	1	0	0	0	0	0	2016	
11998	165	229.92	69844	0	0	0	0	0	0	1	0	0	0	0	0	2016	
11785	168	251.80	82566	0	0	0	0	0	0	1	0	0	0	0	0	2016	
11849	168	203.66	50928	0	0	0	0	0	0	0	1	0	0	0	0	2016	
11975	168	181.51	38837	0	0	0	0	0	0	0	1	0	0	0	0	2016	
11869	168	197.33	48423	0	0	0	0	0	0	0	1	0	0	0	0	2016	
11873	168	185.89	41823	0	0	0	0	0	0	0	1	0	0	0	0	2016	
11540	168	220.92	62599	0	0	0	0	0	0	0	1	0	0	0	0	2016	
12848	168	141.07	20203	0	0	0	0	0	0	0	0	1	0	0	0	2016	
12797	69	150.29	10072	0	0	0	0	0	0	0	0	1	0	0	0	2016	
11039	63	311.25	52650	0	0	0	0	0	0	0	0	1	0	0	1	2016	
11405	168	261.27	91113	0	0	0	0	0	0	0	0	1	0	0	0	2016	
11673	168	188.33	44370	0	0	0	0	0	0	0	0	0	1	0	0	2016	
11670	168	187.08	42398	0	0	0	0	0	0	0	0	0	1	0	0	2016	
11954	167	177.86	35202	0	0	0	0	0	0	0	0	0	1	0	0	2016	
12141	168	171.57	33725	0	0	0	0	0	0	0	0	0	1	0	0	2016	
10368	165	214.74	59315	0	0	0	0	0	0	0	0	0	1	0	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2016	
13078	99	146.24	15737	0	0	0	0	0	0	0	0	0	0	0	1	2016	
12110	168	176.54	33928	0	0	0	0	0	0	0	0	0	0	0	0	2016	
11702	168	157.55	27354	0	0	0	0	0	0	0	0	0	0	0	0	2016	
11549	24	137.17	2857	0	0	0	0	0	0	0	0	0	0	0	0	2016	
11371	50	274.50	24718	1	0	0	0	0	0	0	0	0	0	0	1	2017	JAN
11077	59	317.76	43181	1	0	0	0	0	0	0	0	0	0	0	0	2017	
11131	45	246.38	18913	1	0	0	0	0	0	0	0	0	0	0	1	2017	
11039	168	278.27	79224	1	0	0	0	0	0	0	0	0	0	0	0	2017	
10092	168	305.00	96253	0	1	0	0	0	0	0	0	0	0	0	0	2017	
9768	135	372.04	121664	0	1	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2017	
11243	167	200.70	47612	0	0	0	0	0	1	0	0	0	0	0	0	2017	
11525	168	173.21	37454	0	0	0	0	0	1	0	0	0	0	0	0	2017	
11771	168	163.48	30461	0	0	0	0	0	1	0	0	0	0	0	0	2017	
12369	144	172.67	39212	0	0	0	0	0	1	0	0	0	0	0	0	2017	
12084	168	169.63	31495	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL
11953	163	157.74	26600	0	0	0	0	0	0	1	0	0	0	0	0	2017	
11488	168	206.37	53221	0	0	0	0	0	0	1	0	0	0	0	0	2017	

Data Base for DANIEL 2 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
11547	168	185.93	40756	0	0	0	0	0	0	1	0	0	0	0	0	2017	
11908	168	172.68	36350	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11987	168	155.45	26168	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11322	168	202.13	45994	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11203	168	199.54	47681	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11955	168	165.02	31893	0	0	0	0	0	0	0	1	0	0	0	0	2017	
11933	168	164.66	32134	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11986	167	145.84	22911	0	0	0	0	0	0	0	0	1	0	0	0	2017	
10995	168	227.79	60429	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11543	168	192.67	42900	0	0	0	0	0	0	0	0	1	0	0	0	2017	
11265	168	173.67	37370	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11130	168	192.77	46312	0	0	0	0	0	0	0	0	0	1	0	0	2017	
12080	78	192.38	24658	0	0	0	0	0	0	0	0	0	1	0	0	2017	
13838	27	134.78	4602	0	0	0	0	0	0	0	0	0	1	0	1	2017	
12542	168	141.52	20398	0	0	0	0	0	0	0	0	0	1	0	0	2017	
11980	168	164.19	32521	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11024	168	213.70	63200	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11630	168	150.30	22954	0	0	0	0	0	0	0	0	0	0	1	0	2017	
12152	168	140.32	19830	0	0	0	0	0	0	0	0	0	0	1	0	2017	
11915	168	153.26	24771	0	0	0	0	0	0	0	0	0	0	0	0	2017	
11804	162	172.36	31084	0	0	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2017	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2017	
10953	168	250.05	72422	1	0	0	0	0	0	0	0	0	0	0	0	2018	JAN
11735	168	209.99	50277	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10933	156	226.03	55739	1	0	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2018	
10630	140	188.52	32287	0	1	0	0	0	0	0	0	0	0	0	1	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
10859	65	228.52	26345	0	0	1	0	0	0	0	0	0	0	0	1	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2018	
12363	113	176.47	25723	0	0	0	1	0	0	0	0	0	0	0	1	2018	
12375	22	165.50	4108	0	0	0	1	0	0	0	0	0	0	0	0	2018	
12218	150	159.89	27582	0	0	0	0	1	0	0	0	0	0	0	1	2018	
11407	168	193.79	44711	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11312	168	177.63	37728	0	0	0	0	1	0	0	0	0	0	0	0	2018	
10824	168	304.90	106007	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11167	168	216.42	49781	0	0	0	0	1	0	0	0	0	0	0	0	2018	
11384	156	183.32	39462	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11222	168	211.73	48122	0	0	0	0	0	1	0	0	0	0	0	0	2018	
10695	167	272.66	80408	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11572	144	184.31	38872	0	0	0	0	0	1	0	0	0	0	0	0	2018	
11513	168	167.18	30955	0	0	0	0	0	0	1	0	0	0	0	0	2018	JUL
12172	168	174.82	33453	0	0	0	0	0	0	1	0	0	0	0	0	2018	
11805	168	162.99	28238	0	0	0	0	0	0	1	0	0	0	0	0	2018	
11239	168	161.42	27889	0	0	0	0	0	0	1	0	0	0	0	0	2018	
11914	168	162.34	28688	0	0	0	0	0	0	0	1	0	0	0	0	2018	

Data Base for DANIEL 2 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
11347	143	177.41	30122	0	0	0	0	0	0	0	1	0	0	0	0	2018	
11373	157	171.93	33617	0	0	0	0	0	0	0	1	0	0	0	1	2018	
11506	168	215.38	50394	0	0	0	0	0	0	0	1	0	0	0	0	2018	
11659	168	182.15	37223	0	0	0	0	0	0	0	1	0	0	0	0	2018	
11838	167	173.40	33199	0	0	0	0	0	0	0	0	1	0	0	0	2018	
11409	168	197.20	40969	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10954	140	230.48	51651	0	0	0	0	0	0	0	0	1	0	0	1	2018	
10839	168	246.98	62222	0	0	0	0	0	0	0	0	1	0	0	0	2018	
10495	168	273.57	78083	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10775	168	219.28	52280	0	0	0	0	0	0	0	0	0	1	0	0	2018	
10940	168	208.15	46968	0	0	0	0	0	0	0	0	0	1	0	0	2018	
11880	145	141.00	17564	0	0	0	0	0	0	0	0	0	1	0	0	2018	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2018	
12546	143	151.04	20881	0	0	0	0	0	0	0	0	0	0	1	1	2018	
11768	168	186.52	40212	0	0	0	0	0	0	0	0	0	0	1	0	2018	
11632	168	156.80	26691	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10758	168	258.78	83332	0	0	0	0	0	0	0	0	0	0	1	0	2018	
10979	165	186.65	39330	0	0	0	0	0	0	0	0	0	0	0	0	2018	
11515	163	179.66	36296	0	0	0	0	0	0	0	0	0	0	0	0	2018	
11447	163	159.61	27294	0	0	0	0	0	0	0	0	0	0	0	0	2018	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2018	
12171	71	153.89	10476	1	0	0	0	0	0	0	0	0	0	0	1	2019	JAN
11979	168	147.24	22231	1	0	0	0	0	0	0	0	0	0	0	0	2019	
11873	168	153.68	25063	1	0	0	0	0	0	0	0	0	0	0	0	2019	
12235	168	150.61	24726	1	0	0	0	0	0	0	0	0	0	0	0	2019	
11669	93	159.14	14612	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2019	
11264	64	168.58	15670	0	0	1	0	0	0	0	0	0	0	0	0	2019	
10931	32	188.25	9454	0	0	1	0	0	0	0	0	0	0	0	1	2019	
10713	168	212.93	54121	0	0	1	0	0	0	0	0	0	0	0	0	2019	
11371	166	189.28	39898	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11014	167	224.24	56962	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11590	168	192.45	40982	0	0	0	1	0	0	0	0	0	0	0	0	2019	
11510	163	197.59	43420	0	0	0	1	0	0	0	0	0	0	0	0	2019	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10348	168	236.02	65471	0	0	0	0	1	0	0	0	0	0	0	0	2019	
10204	109	248.71	52027	0	0	0	0	1	0	0	0	0	0	0	1	2019	
11359	168	167.57	31152	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11765	168	174.81	34319	0	0	0	0	0	1	0	0	0	0	0	0	2019	
10882	164	216.26	58475	0	0	0	0	0	1	0	0	0	0	0	0	2019	
11045	144	203.48	51375	0	0	0	0	0	1	0	0	0	0	0	0	2019	

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
7281	168	477.57	233355	0	0	0	0	0	0	1	0	0	0	0	0	2016	JUL
7337	168	482.67	238080	0	0	0	0	0	0	1	0	0	0	0	0	2016	
7243	168	480.15	235872	0	0	0	0	0	0	1	0	0	0	0	0	2016	
7104	168	491.04	245364	0	0	0	0	0	0	1	0	0	0	0	0	2016	
7126	168	482.27	236875	0	0	0	0	0	0	0	1	0	0	0	0	2016	
7224	168	493.19	246969	0	0	0	0	0	0	0	1	0	0	0	0	2016	
7173	168	486.73	239691	0	0	0	0	0	0	0	1	0	0	0	0	2016	
7143	168	477.67	232997	0	0	0	0	0	0	0	1	0	0	0	0	2016	
7157	168	402.43	178526	0	0	0	0	0	0	0	1	0	0	0	0	2016	
7337	162	456.25	218248	0	0	0	0	0	0	0	0	1	0	0	0	2016	
7351	143	478.22	200584	0	0	0	0	0	0	0	0	1	0	0	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2016	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2016	
7263	117	413.13	163041	0	0	0	0	0	0	0	0	0	0	1	1	2016	
6923	168	570.43	328652	0	0	0	0	0	0	0	0	0	0	1	0	2016	
6918	168	538.77	296105	0	0	0	0	0	0	0	0	0	0	1	0	2016	
7353	112	446.53	164893	0	0	0	0	0	0	0	0	0	0	1	1	2016	
6916	168	516.12	272191	0	0	0	0	0	0	0	0	0	0	0	0	2016	
6934	168	494.47	256605	0	0	0	0	0	0	0	0	0	0	0	0	2016	
7054	168	518.71	280205	0	0	0	0	0	0	0	0	0	0	0	0	2016	
6983	168	425.23	185778	0	0	0	0	0	0	0	0	0	0	0	0	2016	
6977	168	507.30	265571	1	0	0	0	0	0	0	0	0	0	0	0	2017	JAN
6976	168	510.79	270023	1	0	0	0	0	0	0	0	0	0	0	0	2017	
7097	168	463.55	222166	1	0	0	0	0	0	0	0	0	0	0	0	2017	
7139	168	433.92	195223	1	0	0	0	0	0	0	0	0	0	0	0	2017	
6795	168	481.38	239890	0	1	0	0	0	0	0	0	0	0	0	0	2017	
6936	168	522.33	277466	0	1	0	0	0	0	0	0	0	0	0	0	2017	
7022	168	488.73	245354	0	1	0	0	0	0	0	0	0	0	0	0	2017	
6849	168	484.58	240357	0	1	0	0	0	0	0	0	0	0	0	0	2017	
6959	168	539.85	294577	0	0	1	0	0	0	0	0	0	0	0	0	2017	
6997	142	518.54	234823	0	0	1	0	0	0	0	0	0	0	0	0	2017	
7003	147	550.03	276337	0	0	1	0	0	0	0	0	0	0	0	1	2017	
6885	168	512.31	268050	0	0	1	0	0	0	0	0	0	0	0	0	2017	
6852	168	492.54	250287	0	0	1	0	0	0	0	0	0	0	0	0	2017	
7001	168	494.70	251649	0	0	0	1	0	0	0	0	0	0	0	0	2017	
7065	168	470.69	235044	0	0	0	1	0	0	0	0	0	0	0	0	2017	
7201	73	444.75	95800	0	0	0	1	0	0	0	0	0	0	0	0	2017	
7037	168	451.72	218624	0	0	0	0	1	0	0	0	0	0	0	0	2017	
7004	168	530.70	287312	0	0	0	0	1	0	0	0	0	0	0	0	2017	
7021	168	517.13	272276	0	0	0	0	1	0	0	0	0	0	0	0	2017	
6924	168	440.05	205067	0	0	0	0	1	0	0	0	0	0	0	0	2017	
6798	168	490.24	246730	0	0	0	0	1	0	0	0	0	0	0	0	2017	
6890	168	482.38	243505	0	0	0	0	0	1	0	0	0	0	0	0	2017	
6914	168	493.60	254407	0	0	0	0	0	1	0	0	0	0	0	0	2017	
6802	168	503.36	258691	0	0	0	0	0	1	0	0	0	0	0	0	2017	
6752	144	486.81	243441	0	0	0	0	0	1	0	0	0	0	0	0	2017	
7114	168	503.93	260260	0	0	0	0	0	0	1	0	0	0	0	0	2017	JUL
7142	168	513.93	269980	0	0	0	0	0	0	1	0	0	0	0	0	2017	

Data Base for SMITH 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
7142	168	514.32	270531	0	0	0	0	0	0	1	0	0	0	0	0	2017	
6981	168	522.38	276550	0	0	0	0	0	0	1	0	0	0	0	0	2017	
6986	168	513.23	268860	0	0	0	0	0	0	0	1	0	0	0	0	2017	
7111	168	519.55	273245	0	0	0	0	0	0	0	1	0	0	0	0	2017	
7233	168	535.57	288881	0	0	0	0	0	0	0	1	0	0	0	0	2017	
6982	168	499.86	254180	0	0	0	0	0	0	0	1	0	0	0	0	2017	
6760	131	507.34	221630	0	0	0	0	0	0	0	1	0	0	0	1	2017	
6892	168	512.79	268030	0	0	0	0	0	0	0	0	1	0	0	0	2017	
6957	168	443.57	208983	0	0	0	0	0	0	0	0	1	0	0	0	2017	
6817	168	543.92	297026	0	0	0	0	0	0	0	0	1	0	0	0	2017	
6588	168	533.24	286068	0	0	0	0	0	0	0	0	1	0	0	0	2017	
6698	168	520.57	273757	0	0	0	0	0	0	0	0	0	1	0	0	2017	
6915	168	524.19	276836	0	0	0	0	0	0	0	0	0	1	0	0	2017	
6755	168	523.05	276729	0	0	0	0	0	0	0	0	0	1	0	0	2017	
6686	168	510.89	264611	0	0	0	0	0	0	0	0	0	1	0	0	2017	
6863	168	551.19	305124	0	0	0	0	0	0	0	0	0	1	0	0	2017	
7032	120	554.82	222739	0	0	0	0	0	0	0	0	0	0	1	0	2017	
6968	168	480.81	237807	0	0	0	0	0	0	0	0	0	0	1	0	2017	
6873	168	521.29	274334	0	0	0	0	0	0	0	0	0	0	1	0	2017	
6956	155	526.39	278443	0	0	0	0	0	0	0	0	0	0	0	0	2017	
6889	168	570.82	327256	0	0	0	0	0	0	0	0	0	0	0	0	2017	
6895	164	498.59	255660	0	0	0	0	0	0	0	0	0	0	0	0	2017	
6929	168	515.48	275897	0	0	0	0	0	0	0	0	0	0	0	0	2017	
6931	168	569.98	333381	1	0	0	0	0	0	0	0	0	0	0	0	2018	JAN
6974	168	496.04	261856	1	0	0	0	0	0	0	0	0	0	0	0	2018	
6951	168	542.71	303020	1	0	0	0	0	0	0	0	0	0	0	0	2018	
7013	168	476.18	241270	1	0	0	0	0	0	0	0	0	0	0	0	2018	
6912	144	503.09	224192	0	1	0	0	0	0	0	0	0	0	0	0	2018	
6943	168	461.39	228004	0	1	0	0	0	0	0	0	0	0	0	0	2018	
7012	168	444.28	216613	0	1	0	0	0	0	0	0	0	0	0	0	2018	
6804	168	512.17	266640	0	1	0	0	0	0	0	0	0	0	0	0	2018	
6797	168	519.15	271330	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6913	149	498.92	238748	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6893	168	516.96	275002	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6940	168	513.57	269160	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6896	144	520.34	238218	0	0	1	0	0	0	0	0	0	0	0	0	2018	
6744	168	536.93	293554	0	0	0	1	0	0	0	0	0	0	0	0	2018	
6713	168	553.95	308278	0	0	0	1	0	0	0	0	0	0	0	0	2018	
6686	168	547.45	301399	0	0	0	1	0	0	0	0	0	0	0	0	2018	
6735	168	515.02	274059	0	0	0	1	0	0	0	0	0	0	0	0	2018	
6742	168	524.11	281447	0	0	0	0	1	0	0	0	0	0	0	0	2018	
6869	168	489.53	254728	0	0	0	0	1	0	0	0	0	0	0	0	2018	
7058	70	303.34	45198	0	0	0	0	1	0	0	0	0	0	0	0	2018	
7181	34	418.18	48894	0	0	0	0	1	0	0	0	0	0	0	1	2018	
7032	144	422.85	171070	0	0	0	0	1	0	0	0	0	0	0	0	2018	
7099	168	479.27	244454	0	0	0	0	0	1	0	0	0	0	0	0	2018	
7099	168	492.67	252798	0	0	0	0	0	1	0	0	0	0	0	0	2018	
7084	168	520.40	275042	0	0	0	0	0	1	0	0	0	0	0	0	2018	
6860	144	489.69	248398	0	0	0	0	0	1	0	0	0	0	0	0	2018	
6839	168	515.08	269230	0	0	0	0	0	0	1	0	0	0	0	0	2018	JUL
6969	168	525.01	278809	0	0	0	0	0	0	1	0	0	0	0	0	2018	
6811	168	535.52	288045	0	0	0	0	0	0	1	0	0	0	0	0	2018	
6552	168	529.67	282107	0	0	0	0	0	0	1	0	0	0	0	0	2018	

Data Base for SMITH 3 Target Heat Rate Equation

HtRt	Hr	AMW	LSRF	J	F	M	A	M	J	J	A	S	O	N	NS	YR	
6842	168	517.51	272976	0	0	0	0	0	0	0	1	0	0	0	0	2018	
7150	168	523.55	277443	0	0	0	0	0	0	0	1	0	0	0	0	2018	
7210	168	515.04	268828	0	0	0	0	0	0	0	1	0	0	0	0	2018	
7139	168	539.03	291964	0	0	0	0	0	0	0	0	1	0	0	0	2018	
7243	168	521.53	276367	0	0	0	0	0	0	0	0	1	0	0	0	2018	
6947	168	512.99	270236	0	0	0	0	0	0	0	0	1	0	0	0	2018	
6684	168	516.04	273503	0	0	0	0	0	0	0	0	1	0	0	0	2018	
6817	168	540.78	293019	0	0	0	0	0	0	0	0	0	1	0	0	2018	
6888	65	543.03	126132	0	0	0	0	0	0	0	0	0	1	0	0	2018	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2018	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2018	
7421	165	239.76	58592	0	0	0	0	0	0	0	0	0	0	1	0	2018	
7324	168	446.08	215083	0	0	0	0	0	0	0	0	0	0	1	0	2018	
7343	168	471.88	229560	0	0	0	0	0	0	0	0	0	0	1	0	2018	
7314	168	517.98	277988	0	0	0	0	0	0	0	0	0	0	1	0	2018	
6774	168	495.83	258993	0	0	0	0	0	0	0	0	0	0	0	0	2018	
6779	168	520.73	283060	0	0	0	0	0	0	0	0	0	0	0	0	2018	
6806	168	391.77	175719	0	0	0	0	0	0	0	0	0	0	0	0	2018	
6808	168	426.10	195164	0	0	0	0	0	0	0	0	0	0	0	0	2018	
6742	168	467.62	230144	1	0	0	0	0	0	0	0	0	0	0	0	2019	JAN
6710	168	540.54	296323	1	0	0	0	0	0	0	0	0	0	0	0	2019	
6721	168	488.64	258124	1	0	0	0	0	0	0	0	0	0	0	0	2019	
6800	168	447.93	218756	1	0	0	0	0	0	0	0	0	0	0	0	2019	
6722	168	498.26	256842	0	1	0	0	0	0	0	0	0	0	0	0	2019	
6682	168	539.41	292640	0	1	0	0	0	0	0	0	0	0	0	0	2019	
6664	168	533.75	285758	0	1	0	0	0	0	0	0	0	0	0	0	2019	
6503	168	536.90	288843	0	1	0	0	0	0	0	0	0	0	0	0	2019	
6900	168	500.96	258935	0	0	1	0	0	0	0	0	0	0	0	0	2019	
6938	167	537.62	292201	0	0	1	0	0	0	0	0	0	0	0	0	2019	
6927	168	526.58	279423	0	0	1	0	0	0	0	0	0	0	0	0	2019	
7060	168	351.72	142988	0	0	1	0	0	0	0	0	0	0	0	0	2019	
6887	168	264.48	70088	0	0	1	0	0	0	0	0	0	0	0	0	2019	
6753	168	259.50	67394	0	0	0	1	0	0	0	0	0	0	0	0	2019	
6821	168	254.39	64759	0	0	0	1	0	0	0	0	0	0	0	0	2019	
6709	168	256.08	65677	0	0	0	1	0	0	0	0	0	0	0	0	2019	
6720	168	249.24	62155	0	0	0	0	1	0	0	0	0	0	0	0	2019	
6850	168	247.01	61040	0	0	0	0	1	0	0	0	0	0	0	0	2019	
6886	25	232.48	8724	0	0	0	0	1	0	0	0	0	0	0	0	2019	
6945	112	259.96	56770	0	0	0	0	1	0	0	0	0	0	0	1	2019	
6553	168	285.54	81989	0	0	0	0	1	0	0	0	0	0	0	0	2019	
6612	168	294.92	87372	0	0	0	0	0	1	0	0	0	0	0	0	2019	
6625	168	279.00	78630	0	0	0	0	0	1	0	0	0	0	0	0	2019	
6608	168	289.74	84134	0	0	0	0	0	1	0	0	0	0	0	0	2019	
6613	111	282.95	68100	0	0	0	0	0	1	0	0	0	0	0	1	2019	

Data Base for SMITH 3 Target Heat Rate Equation

HtRt	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hr	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
J to N	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
YR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Calculation of
Target Average Net Operating Heat Rates
for January 2020 - December 2020

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKWH * 10^3 Generation	(5) Weighted ANOHR Target
SCHERER 3	Jan '20	558.4	345,302	10,626	409,310	
	Feb '20	552.7	338,295	10,489	265,835	
	Mar '20	615.3	419,128	10,391	255,359	
	Apr '20	534.1	315,926	10,792	321,002	
	May '20	536.0	318,176	10,672	390,768	
	Jun '20	619.8	425,268	10,613	410,958	
	Jul '20	646.5	462,608	10,587	474,496	
	Aug '20	644.3	459,472	10,482	470,978	
	Sep '20	615.6	419,536	10,659	437,059	
	Oct '20	537.9	320,435	10,668	350,701	
	Nov '20	423.8	198,785	10,823	235,235	
	Dec '20	561.0	348,521	10,621	381,501	10,616
CRIST 7	Jan '20	332.0	105,536	10,381	165,008	
	Feb '20	297.5	80,806	10,490	143,687	
	Mar '20	388.3	152,748	10,278	8,155	
	Apr '20	303.5	84,877	10,386	28,830	
	May '20	320.0	96,572	10,461	184,636	
	Jun '20	352.0	121,334	10,597	249,579	
	Jul '20	341.7	113,064	10,637	250,466	
	Aug '20	341.2	112,669	10,639	250,074	
	Sep '20	243.5	48,506	11,195	23,372	
	Oct '20	0.0	0	-	0	
	Nov '20	225.9	39,669	10,656	120,190	
	Dec '20	226.0	39,717	11,345	32,318	10,584

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on Page 2 of Schedule 1.

Column (5) = $(\Sigma ((3) * (4))) / (\Sigma (4))$

Calculation of
Target Average Net Operating Heat Rates
for January 2020 - December 2020

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKWH * 10^3 Generation	(5) Weighted ANOHR Target
DANIEL 1	Jan '20	186.4	34,996	11,880	103,651	
	Feb '20	157.2	24,631	12,044	49,058	
	Mar '20	202.5	41,482	11,851	92,148	
	Apr '20	172.5	29,837	11,786	76,063	
	May '20	190.9	36,754	11,536	13,745	
	Jun '20	217.1	47,837	11,265	153,490	
	Jul '20	244.8	61,131	11,054	133,179	
	Aug '20	247.3	62,411	11,037	180,787	
	Sep '20	253.5	65,641	10,999	46,650	
	Oct '20	0.0	0	-	0	
	Nov '20	0.0	0	-	0	
	Dec '20	0.0	0	-	0	11,404
DANIEL 2	Jan '20	204.7	43,591	11,373	103,575	
	Feb '20	198.5	41,392	10,556	71,454	
	Mar '20	0.0	0	-	0	
	Apr '20	260.7	65,883	10,955	35,715	
	May '20	205.2	43,771	11,056	55,621	
	Jun '20	246.9	59,985	11,041	142,710	
	Jul '20	278.1	73,697	11,039	181,308	
	Aug '20	278.6	73,928	10,857	191,140	
	Sep '20	254.3	63,115	10,994	174,678	
	Oct '20	227.7	52,219	11,177	131,138	
	Nov '20	0.0	0	-	0	
	Dec '20	196.6	40,728	11,453	117,188	11,057
SMITH 3	Jan '20	585.5	343,737	6,874	386,453	
	Feb '20	571.9	327,825	6,808	365,444	
	Mar '20	610.2	373,594	6,864	353,323	
	Apr '20	612.3	376,189	6,863	353,908	
	May '20	608.0	370,884	6,865	354,470	
	Jun '20	584.8	342,909	6,874	395,339	
	Jul '20	592.1	351,594	6,994	433,381	
	Aug '20	597.2	357,726	7,022	421,592	
	Sep '20	591.3	350,637	6,951	235,913	
	Oct '20	610.9	374,458	6,763	404,428	
	Nov '20	597.9	358,571	7,044	388,629	
	Dec '20	588.4	347,178	6,872	398,370	6,900

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on Page 2 of Schedule 1.

Column (5) = $(\Sigma ((3) * (4))) / (\Sigma (4))$

Summary of Target, Maximum, and Minimum
Average Net Operating Heat Rates
for January 2020 - December 2020

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
SCHERER 3	10,616	10,298	10,934
CRIST 7	10,584	10,266	10,902
DANIEL 1	11,404	11,062	11,746
DANIEL 2	11,057	10,725	11,389
SMITH 3	6,900	6,693	7,107

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2020 - December 2020

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '20 - Dec '20	Reserve Shutdown Hours for Jan '20 - Dec '20	Target Equivalent Availability **
Scherer 3	0.0342	0	822	96.8
Crist 7	0.1218	1,223	2,265	78.4
Daniel 1	0.0773	2,065	2,318	70.9
Daniel 2	0.0766	888	2,389	84.7
Smith 3	0.0376	600	358	89.9

* For Period July 2014 through June 2019.

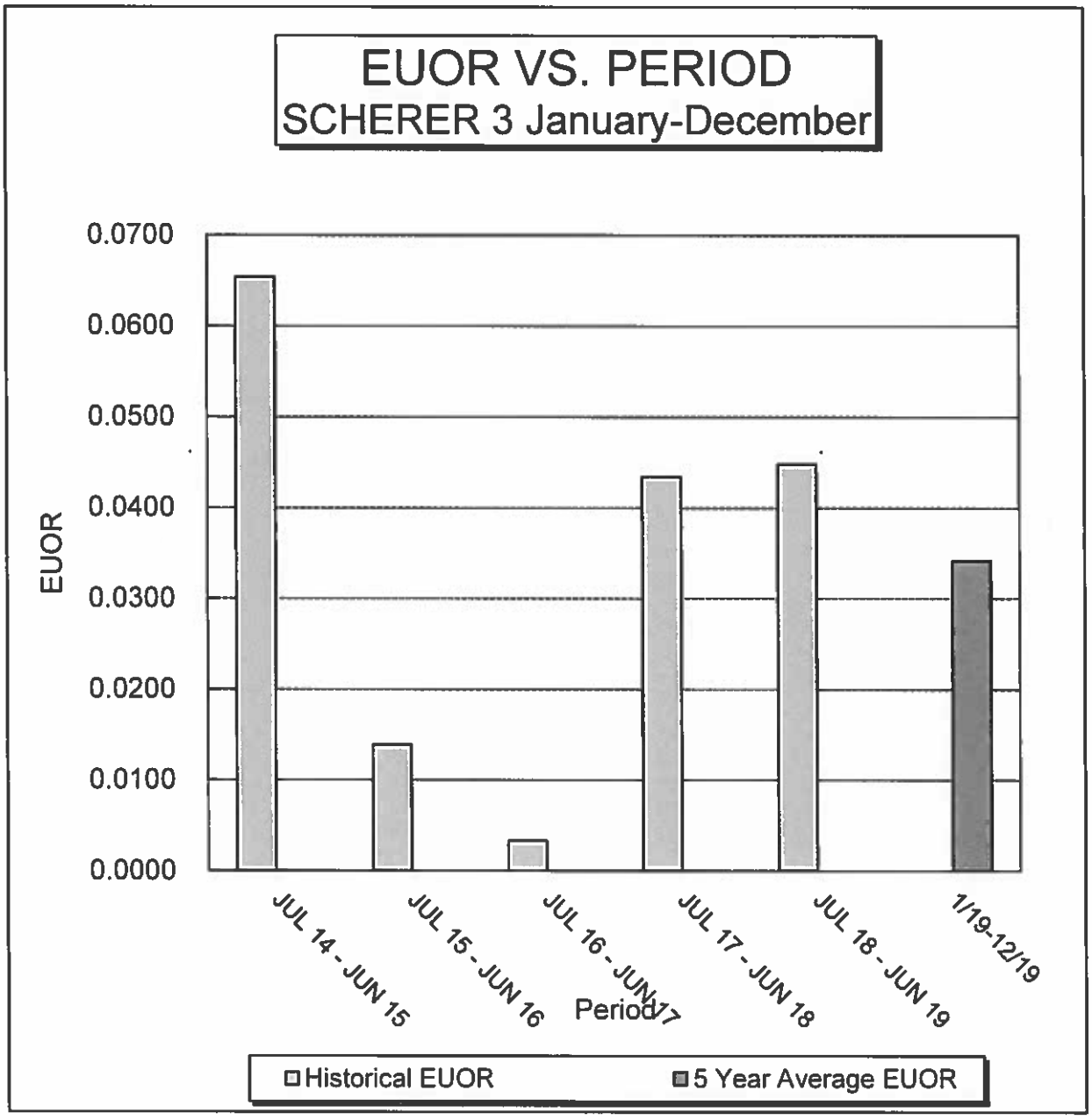
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

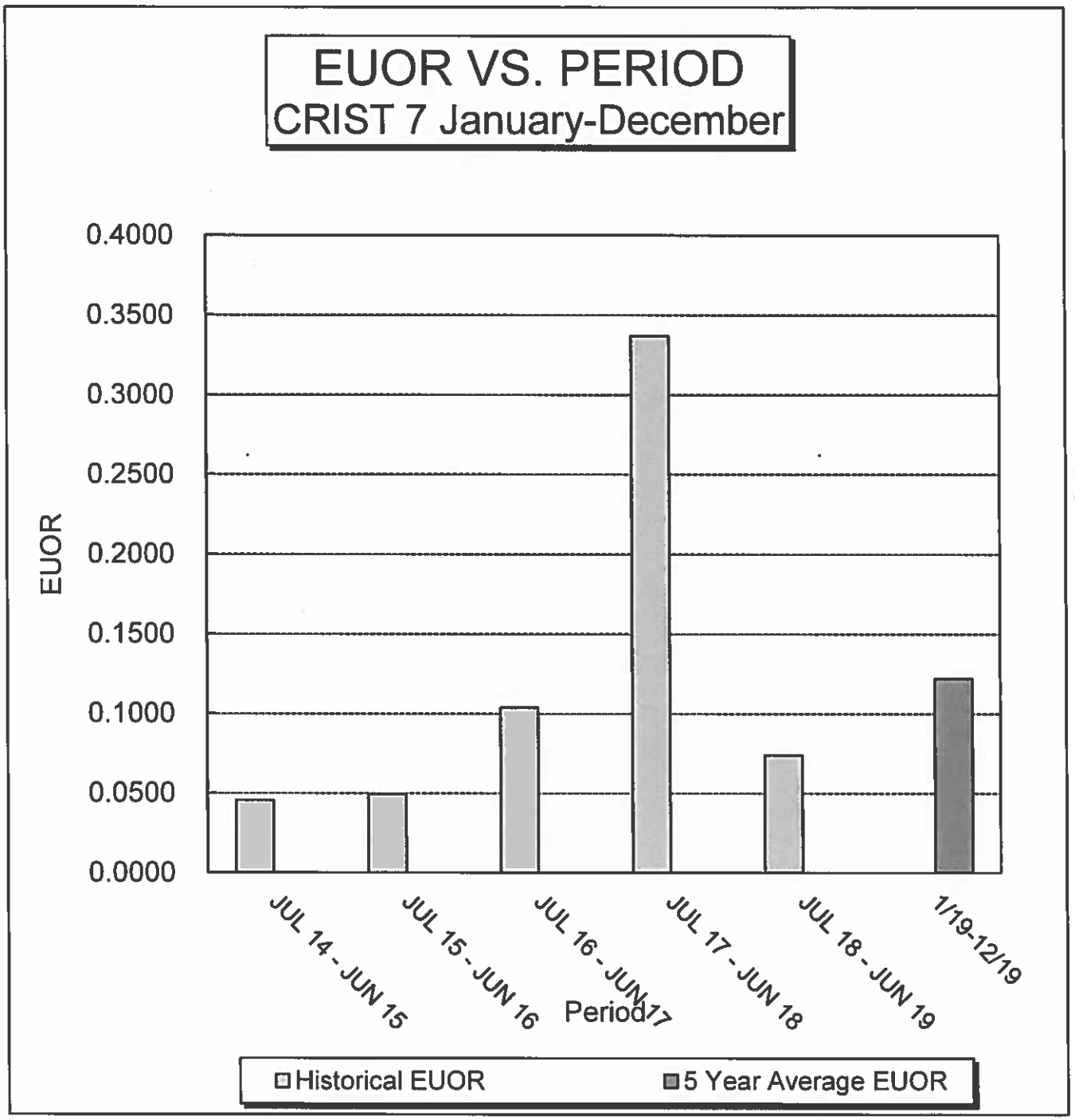
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2020 - December 2020

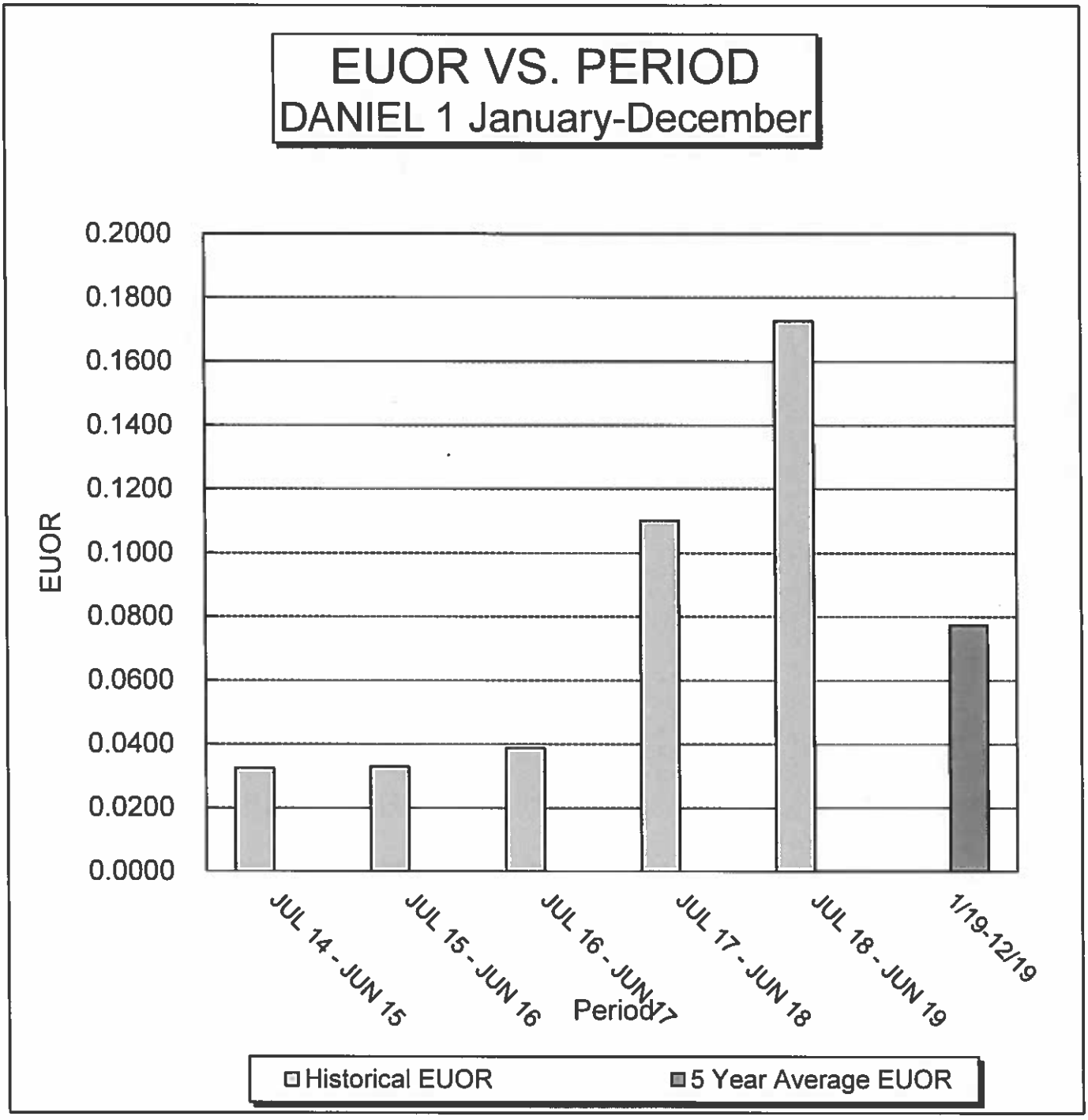
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Scherer 3	0.0342	0.0239	97.8	0.0496	95.5
Crist 7	0.1218	0.0853	80.9	0.1766	75.4
Daniel 1	0.0773	0.0541	73.8	0.1121	70.9
Daniel 2	0.0766	0.0536	86.5	0.1111	82.9
Smith 3	0.0376	0.0263	90.8	0.0545	88.3

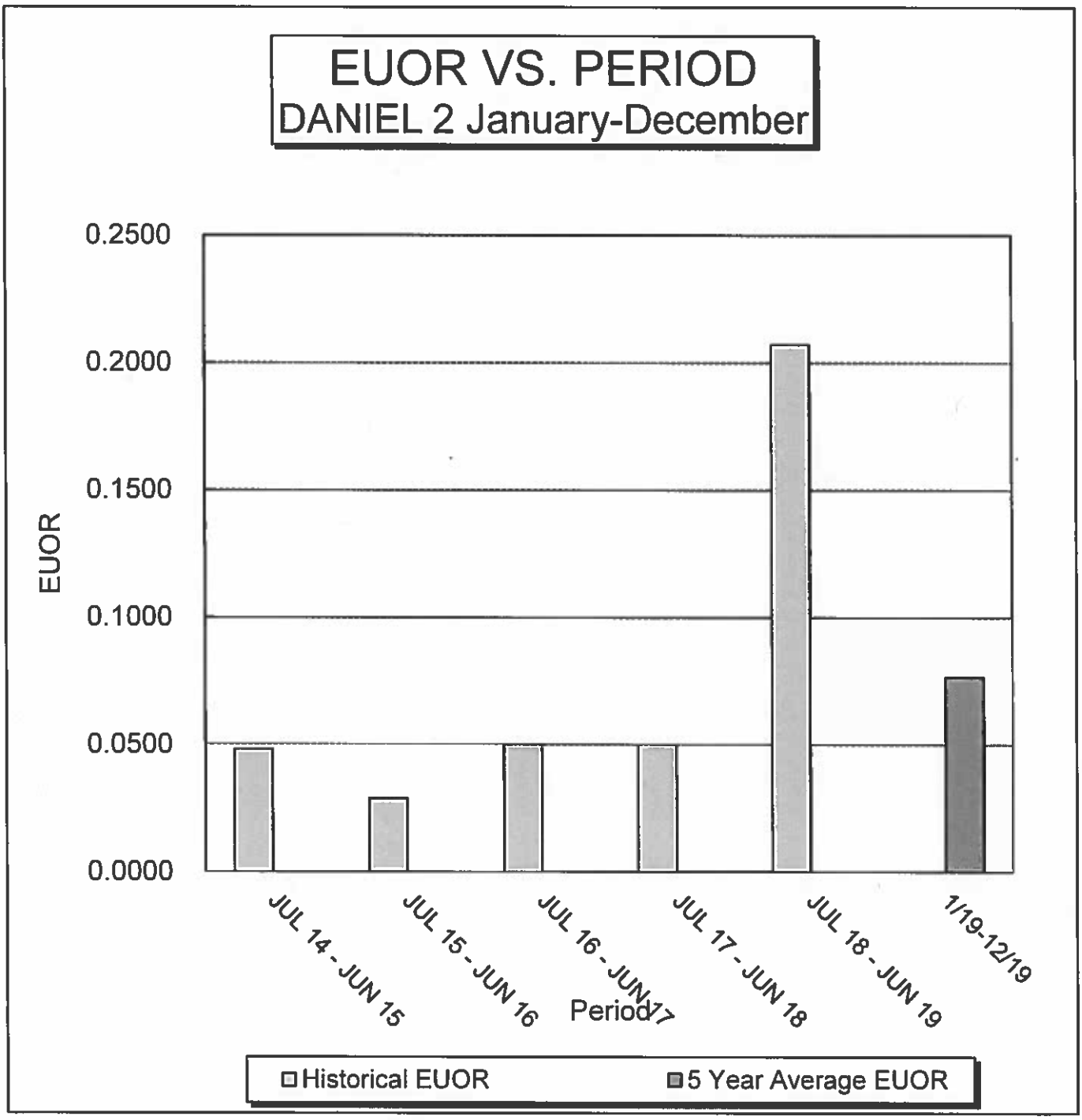
Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2020 - December 2020

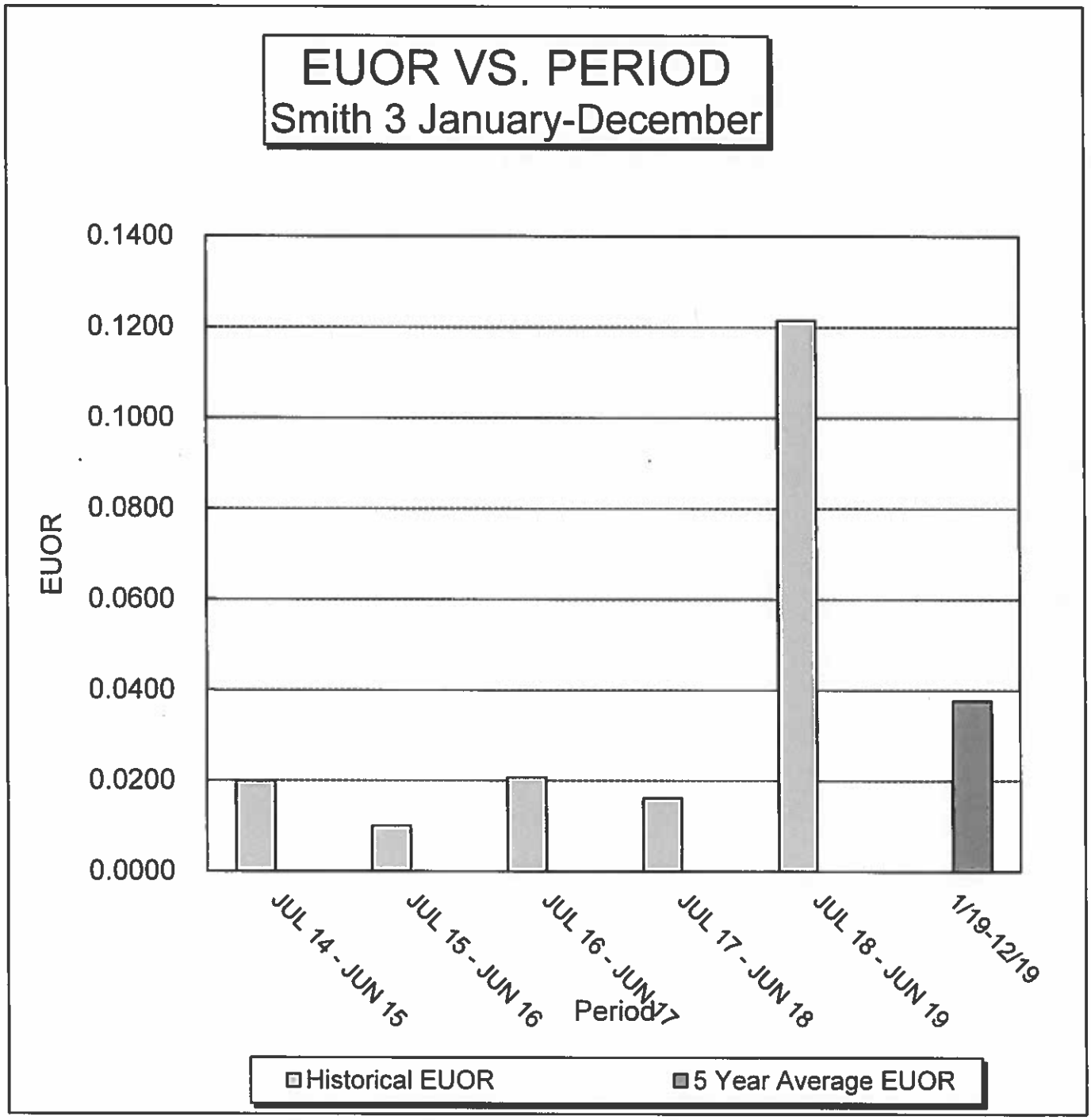
Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Scherer 3	96.8	97.8	95.5
Crist 7	78.4	80.9	75.4
Daniel 1	70.9	73.8	70.9
Daniel 2	84.7	86.5	82.9
Smith 3	89.9	90.8	88.3


EUOR VS. PERIOD
SCHERER 3 January-December
EUOR
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
JUL 14 - JUN 15
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
1/19-12/19
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 7 January-December
0.4000
0.3500
0.3000
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
JUL 14 - JUN 15
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
1/19-12/19
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 1 January-December
EUOR
0.2000
0.1800
0.1600
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
JUL 14 - JUN 15
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
1/19-12/19
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 2 January-December
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
JUL 14 - JUN 15
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
1/19-12/19
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
Smith 3 January-December
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
JUL 14 - JUN 15
JUL 15 - JUN 16
JUL 16 - JUN 17
JUL 17 - JUN 18
JUL 18 - JUN 19
1/19-12/19
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE PERIOD JANUARY 2020 - DECEMBER 2020

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Generating Performance Incentive Factor

Estimated 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	-246
- 2	-1004	-491
- 3	-1506	-737
- 4	-2008	-982
- 5	-2510	-1228
- 6	-3011	-1474
- 7	-3513	-1719
- 8	-4015	-1965
- 9	-4517	-2210
- 10	-5019	-2456
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

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Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Estimated

Gulf Power Company

Period of: January 2020 - December 2020

Line 1	Beginning of Period Balance of Common Equity	$1,677,231,110
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '20	$2,390,680,473
Line 3	Month of Feb '20	$2,407,957,894
Line 4	Month of Mar '20	$2,422,753,690
Line 5	Month of Apr '20	$2,434,596,947
Line 6	Month of May '20	$2,454,101,702
Line 7	Month of Jun '20	$2,478,329,836
Line 8	Month of Jul '20	$2,504,920,590
Line 9	Month of Aug '20	$2,270,784,586
Line 10	Month of Sep '20	$2,291,343,846
Line 11	Month of Oct '20	$2,306,180,845
Line 12	Month of Nov '20	$2,318,288,875
Line 13	Month of Dec '20	$2,332,301,723
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$2,329,959,394
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	74.4147%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$7,827,618
Line 18	Jurisdictional Sales (KWH)	10,802,821,821
Line 19	Total Territorial Sales (KWH)	11,100,555,340
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	97.3179%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$7,617,670
Line 22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF point level from sheet 6.391.7)	$2,456,000
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF Pt. leve (The lesser of Line 21 and Line 22)	$2,456,000

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2020 - December 2020

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Scherer 3	0.5%	96.8	97.8	95.5	$23	($35)
Crist 7	0.1%	78.4	80.9	75.4	$4	($5)
Daniel 1	0.0%	70.9	73.8	70.9	$1	($2)
Daniel 2	0.1%	84.7	86.5	82.9	$3	($4)
Smith 3	1.3%	89.9	90.8	88.3	$66	($158)

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Min BTU/KWH	ANOHR Range Max BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Scherer 3	24.7%	10,616	66.2	10,298	10,934	$1,211	($1,211)
Crist 7	7.4%	10,584	64.7	10,266	10,902	$365	($365)
Daniel 1	1.3%	11,404	42.2	11,062	11,746	$64	($64)
Daniel 2	3.3%	11,057	47.5	10,725	11,389	$164	($164)
Smith 3	61.3%	6,900	93.7	6,693	7,107	$3,011	($3,011)

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2020 - December 2020

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target			Actual Performance 1st Prior Period Jul '18 - Jun '19			Actual Performance 2nd Prior Period Jul '17 - Jun '18		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Scherer 3	0.5%	23.7%	0.0000	0.0316	0.0342	0.1869	0.0363	0.0448	0.0000	0.0421	0.0434
Crist 7	0.1%	4.1%	0.1392	0.0771	0.1218	0.0417	0.0659	0.0739	0.1794	0.2710	0.3370
Daniel 1	0.0%	1.0%	0.2351	0.0454	0.0773	0.0000	0.1245	0.1726	0.1545	0.0802	0.1101
Daniel 2	0.1%	3.1%	0.1011	0.0521	0.0766	0.0000	0.1722	0.2070	0.0247	0.0353	0.0498
Smith 3	1.3%	68.0%	0.0683	0.0324	0.0376	0.0230	0.1183	0.1214	0.0499	0.0153	0.0161
Weighted GPIF System Average:			0.0578	0.0348	0.0419	0.0617	0.0984	0.1045	0.0437	0.0335	0.0378

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2020 - December 2020

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '16 - Jun '17			Actual Performance 4th Prior Period Jul '15 - Jun '16			Actual Performance 5th Prior Period Jul '14 - Jun '15		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Scherer 3	0.5%	23.7%	0.1499	0.0024	0.0033	0.0000	0.0120	0.0139	0.1589	0.0550	0.0654
Crist 7	0.1%	4.1%	0.2417	0.0785	0.1036	0.1133	0.0322	0.0490	0.1938	0.0363	0.0453
Daniel 1	0.0%	1.0%	0.0372	0.0315	0.0387	0.0124	0.0135	0.0328	0.2231	0.0185	0.0324
Daniel 2	0.1%	3.1%	0.2074	0.0280	0.0497	0.0102	0.0153	0.0287	0.0495	0.0335	0.0480
Smith 3	1.3%	68.0%	0.1704	0.0171	0.0207	0.0583	0.0090	0.0100	0.0614	0.0182	0.0198
Weighted GPIF System Average:			0.1683	0.0166	0.0211	0.0448	0.0109	0.0133	0.0913	0.0281	0.0327

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Average Net Operating Heat Rate

Gulf Power Company

Period of: January 2020 - December 2020

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '18 - Jun '19	2nd Prior Period Heat Rate Jul '17 - Jun '18	3rd Prior Period Heat Rate Jul '16 - Jun '17
Scherer 3	24.7%	25.2%	10,616	10,666	10,637	10,560
Crist 7	7.4%	7.6%	10,584	10,549	10,564	10,448
Daniel 1	1.3%	1.3%	11,404	11,276	11,368	11,513
Daniel 2	3.3%	3.4%	11,057	10,934	11,014	11,468
Smith 3	61.3%	62.5%	6,900	6,827	6,928	6,990
Weighted GPIF System Average:			8,315	8,274	8,335	8,363

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Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 7 Jul '17 - Jun '18

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun	
1. Target Heat Rate*	10637.0 10381.0	10639.0 10490.0	11195.0 10278.0	- 10386.0	10656.0 10461.0	11345.0 10597.0	
2. Target Heat Rate at Actual Conditions**	10681.0 10201.0	10629.0 10364.0	10647.0 0.0	10534.0 0.0	10315.0 10526.0	10845.0 10726.0	
3. Adjustments to Actual Heat Rate (1-2)	-44.0 180.0	10.0 126.0	548.0 10278.0	0.0 10386.0	341.0 -65.0	500.0 -129.0	
4. Actual Heat Rate for Prior Period	10496.0 10330.0	10692.0 10237.0	10663.0 0.0	10629.0 0.0	10039.0 10549.0	11501.0 10747.0	
5. Adjusted actual Heat Rate (4+3)	10452.0 10510.0	10702.0 10363.0	11211.0 10278.0	10629.0 10386.0	10380.0 10484.0	12001.0 10618.0	
6. Forecast Net MWH Generation*	250466.4 165007.5	250074.4 143686.8	23371.5 8155.2	0.0 28830.2	120190.2 184635.7	32318.0 249579.3	
7. Adjusted Actual Heat Rate for Jul '17 - Jun '18 = (Σ ((5)*(6)))/(Σ (6))							10,564

* For the January 2020 - December 2020 time period.

** Based on the target heat rate equation from Page 2 of Schedule 1 using actual rather than forecast variable values.

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Derivation of Weighting Factors

Gulf Power Company

Period of: January 2020 - December 2020

Plant & Unit	Unit Performance Indicator	Production Cost Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Scherer 3	EA-3	$302,320	$302,297	$23	0.5%
Scherer 3	ANOHR-3	$302,320	$301,109	$1,211	24.7%
Crist 7	EA-4	$302,320	$302,316	$4	0.1%
Crist 7	ANOHR-4	$302,320	$301,955	$365	7.4%
Daniel 1	EA-5	$302,320	$302,319	$1	0.0%
Daniel 1	ANOHR-5	$302,320	$302,256	$64	1.3%
Daniel 2	EA-6	$302,320	$302,317	$3	0.1%
Daniel 2	ANOHR-6	$302,320	$302,156	$164	3.3%
Smith 3	EA-7	$302,320	$302,254	$66	1.3%
Smith 3	ANOHR-7	$302,320	$299,309	$3,011	61.3%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other unit performance indicators at target.

(3) Expressed in replacement energy costs. Also includes variable operating and maintenance expense savings associated with availability improvements.

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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	97.71	+ 9	1,090	10,322
+ 8	18	97.62	+ 8	969	10,347
+ 7	16	97.53	+ 7	848	10,371
+ 6	14	97.44	+ 6	727	10,395
+ 5	12	97.35	+ 5	606	10,420
+ 4	9	97.26	+ 4	484	10,444
+ 3	7	97.17	+ 3	363	10,468
+ 2	5	97.08	+ 2	242	10,492
+ 1	2	96.99	+ 1	121	10,517
				0	10,541
0	0	96.90	0	0	10,616
				0	10,691
- 1	(4)	96.76	- 1	(121)	10,715
- 2	(7)	96.62	- 2	(242)	10,740
- 3	(11)	96.48	- 3	(363)	10,764
- 4	(14)	96.34	- 4	(484)	10,788
- 5	(18)	96.20	- 5	(606)	10,813
- 6	(21)	96.06	- 6	(727)	10,837
- 7	(25)	95.92	- 7	(848)	10,861
- 8	(28)	95.78	- 8	(969)	10,885
- 9	(32)	95.64	- 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

Crist 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	80.68	+ 9	329	10,290
+ 8	3	80.46	+ 8	292	10,315
+ 7	3	80.24	+ 7	256	10,339
+ 6	2	80.02	+ 6	219	10,363
+ 5	2	79.80	+ 5	183	10,388
+ 4	2	79.58	+ 4	146	10,412
+ 3	1	79.36	+ 3	110	10,436
+ 2	1	79.14	+ 2	73	10,460
+ 1	0	78.92	+ 1	37	10,485
				0	10,509
0	0	78.70	0	0	10,584
				0	10,659
- 1	(1)	78.37	- 1	(37)	10,683
- 2	(1)	78.04	- 2	(73)	10,708
- 3	(2)	77.71	- 3	(110)	10,732
- 4	(2)	77.38	- 4	(146)	10,756
- 5	(3)	77.05	- 5	(183)	10,781
- 6	(3)	76.72	- 6	(219)	10,805
- 7	(4)	76.39	- 7	(256)	10,829
- 8	(4)	76.06	- 8	(292)	10,853
- 9	(5)	75.73	- 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	73.68	+ 9	58	11,089
+ 8	1	73.56	+ 8	51	11,115
+ 7	1	73.44	+ 7	45	11,142
+ 6	1	73.32	+ 6	38	11,169
+ 5	1	73.20	+ 5	32	11,196
+ 4	0	73.08	+ 4	26	11,222
+ 3	0	72.96	+ 3	19	11,249
+ 2	0	72.84	+ 2	13	11,276
+ 1	0	72.72	+ 1	6	11,302
				0	11,329
0	0	72.60	0	0	11,404
				0	11,479
- 1	(0)	72.43	- 1	(6)	11,506
- 2	(0)	72.26	- 2	(13)	11,532
- 3	(1)	72.09	- 3	(19)	11,559
- 4	(1)	71.92	- 4	(26)	11,586
- 5	(1)	71.75	- 5	(32)	11,613
- 6	(1)	71.58	- 6	(38)	11,639
- 7	(1)	71.41	- 7	(45)	11,666
- 8	(2)	71.24	- 8	(51)	11,693
- 9	(2)	71.07	- 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	86.36	+ 9	148	10,751
+ 8	2	86.22	+ 8	131	10,776
+ 7	2	86.08	+ 7	115	10,802
+ 6	2	85.94	+ 6	98	10,828
+ 5	2	85.80	+ 5	82	10,854
+ 4	1	85.66	+ 4	66	10,879
+ 3	1	85.52	+ 3	49	10,905
+ 2	1	85.38	+ 2	33	10,931
+ 1	0	85.24	+ 1	16	10,956
				0	10,982
0	0	85.10	0	0	11,057
				0	11,132
- 1	(0)	84.88	- 1	(16)	11,158
- 2	(1)	84.66	- 2	(33)	11,183
- 3	(1)	84.44	- 3	(49)	11,209
- 4	(2)	84.22	- 4	(66)	11,235
- 5	(2)	84.00	- 5	(82)	11,261
- 6	(2)	83.78	- 6	(98)	11,286
- 7	(3)	83.56	- 7	(115)	11,312
- 8	(3)	83.34	- 8	(131)	11,338
- 9	(4)	83.12	- 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	90.70	+ 9	2,710	6,706
+ 8	53	90.60	+ 8	2,409	6,719
+ 7	46	90.50	+ 7	2,108	6,733
+ 6	40	90.40	+ 6	1,807	6,746
+ 5	33	90.30	+ 5	1,506	6,759
+ 4	26	90.20	+ 4	1,204	6,772
+ 3	20	90.10	+ 3	903	6,785
+ 2	13	90.00	+ 2	602	6,799
+ 1	7	89.90	+ 1	301	6,812
				0	6,825
0	0	89.80	0	0	6,900
				0	6,975
- 1	(16)	89.65	- 1	(301)	6,988
- 2	(32)	89.50	- 2	(602)	7,001
- 3	(47)	89.35	- 3	(903)	7,015
- 4	(63)	89.20	- 4	(1,204)	7,028
- 5	(79)	89.05	- 5	(1,506)	7,041
- 6	(95)	88.90	- 6	(1,807)	7,054
- 7	(111)	88.75	- 7	(2,108)	7,067
- 8	(126)	88.60	- 8	(2,409)	7,081
- 9	(142)	88.45	- 9	(2,710)	7,094
- 10	(158)	88.30	- 10	(3,011)	7,107
Weighting Factor:		0.013	Weighting Factor:		0.613

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Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2020 - December 2020

It is important to understand that estimated dates for planned outages and their bar chart schedules are frequently changed in timing and work scope due to system conditions, findings of inspections, subcontractor requirements, material availability and so on.

Please note that in addition to the outages scheduled for the target period of January 2020 - December 2020, the outages shown below are currently planned and could be rescheduled for the target period.

Plant & Unit	Planned Outage Dates	Reason for Outage
None		

ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED 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 (%)	98.8	98.7	79.5	95.4	98.8	98.8	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.2	1.3	20.5	4.6	1.2	1.2	
4.	EUOR (%)	1.2	1.8	26.8	5.2	1.2	1.3	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	733.0	481.0	415.0	601.0	729.0	663.0	
7.	RSH	2.0	206.0	176.0	86.0	6.0	48.0	
8.	UH	9.0	9.0	152.0	33.0	9.0	9.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	9.0	9.0	8.0	9.0	9.0	9.0	
11.	MOH & EMOH	0.0	0.0	144.0	24.0	0.0	0.0	
12.	Oper MBtu	4349332	2788341	2653430	3464254	4170279	4361497	
13.	Net Gen (MWH)	409310.4	265834.8	255358.5	321002.0	390768.3	410958.0	
14.	ANOHR (Btu/KWH)	10626.0	10489.0	10391.0	10792.0	10672.0	10613.0	
15.	NOF %	64.6	63.9	71.1	61.7	62.0	71.7	
16.	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

ESTIMATED 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 (%)	98.8	98.8	98.8	98.7	98.6	98.7	96.8
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	1.2	1.2	1.2	1.3	1.4	1.3	3.2
4.	EUOR (%)	1.2	1.2	1.3	1.5	1.8	1.4	3.5
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	734.0	731.0	710.0	652.0	555.0	680.0	7684.0
7.	RSH	1.0	4.0	1.0	82.0	156.0	54.0	822.0
8.	UH	9.0	9.0	9.0	10.0	10.0	10.0	278.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	9.0	9.0	9.0	10.0	10.0	10.0	110.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	168.0
12.	Oper MBtu	5023490	4936791	4658611	3741275	2545948	4051923	46745171
13.	Net Gen (MWH)	474496.1	470978.0	437058.9	350700.7	235234.9	381501.1	4403201.7
14.	ANOHR (Btu/KWH)	10587.0	10482.0	10659.0	10668.0	10823.0	10621.0	10616.0
15.	NOF %	74.7	74.5	71.2	62.2	49.0	64.9	66.2
16.	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

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	CRIST 7	Jan '20	Feb '20	Mar '20	Apr '20	May '20	Jun '20	
1.	EAF (%)	98.9	98.9	19.2	13.3	89.4	98.9	
2.	POF (%)	0.0	0.0	80.6	86.7	0.0	0.0	
3.	EUOF (%)	1.1	1.1	0.2	0.0	10.6	1.1	
4.	EUOR (%)	1.6	1.6	4.5	0.0	12.0	1.1	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	497.0	483.0	21.0	95.0	577.0	709.0	
7.	RSH	239.0	205.0	122.0	1.0	88.0	3.0	
8.	UH	8.0	8.0	600.0	624.0	79.0	8.0	
9.	POH	0.0	0.0	599.0	624.0	0.0	0.0	
10.	FOH & EFOH	8.0	8.0	0.0	0.0	7.0	8.0	
11.	MOH & EMOH	0.0	0.0	1.0	0.0	72.0	0.0	
12.	Oper MBtu	1712943	1507275	83819	299431	1931474	2644791	
13.	Net Gen (MWH)	165007.5	143686.8	8155.2	28830.2	184635.7	249579.3	
14.	ANOHR (Btu/KWH)	10381.0	10490.0	10278.0	10386.0	10461.0	10597.0	
15.	NOF %	69.9	62.6	81.8	63.9	67.4	74.1	
16.	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

Issued by: Gulf Power Company

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2020 - December 2020

	CRIST 7	Jul '20	Aug '20	Sep '20	Oct '20	Nov '20	Dec '20	Total
1.	EAF (%)	98.9	99.2	59.0	69.9	98.9	95.7	78.4
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	13.9
3.	EUOF (%)	1.1	0.8	41.0	30.1	1.1	4.3	7.7
4.	EUOR (%)	1.1	0.8	75.4	100.0	1.5	18.3	12.8
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	733.0	733.0	96.0	0.0	532.0	143.0	4619.0
7.	RSH	3.0	5.0	329.0	520.0	181.0	569.0	2265.0
8.	UH	8.0	6.0	295.0	224.0	8.0	32.0	1900.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1223.0
10.	FOH & EFOH	8.0	6.0	7.0	8.0	8.0	8.0	76.0
11.	MOH & EMOH	0.0	0.0	288.0	216.0	0.0	24.0	601.0
12.	Oper MBtu	2664211	2660541	261644	0	1280746	366648	15413523
13.	Net Gen (MWH)	250466.4	250074.4	23371.5	0.0	120190.2	32318.0	1456315.2
14.	ANOHR (Btu/KWH)	10637.0	10639.0	11195.0	-	10656.0	11345.0	10584.0
15.	NOF %	68.3	68.2	48.7	0.0	45.2	45.2	64.7
16.	NPC (MW)	500.0	500.0	500.0	500.0	500.0	500.0	487.5

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

ESTIMATED 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 (%)	98.3	98.3	72.8	96.0	60.2	98.2	
2.	POF (%)	0.0	0.0	25.8	3.3	0.0	0.0	
3.	EUOF (%)	1.7	1.7	1.4	0.7	39.8	1.8	
4.	EUOR (%)	2.3	3.7	2.2	1.1	80.4	1.8	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	556.0	312.0	455.0	441.0	72.0	707.0	
7.	RSH	175.0	372.0	86.0	250.0	376.0	0.0	
8.	UH	13.0	12.0	202.0	29.0	296.0	13.0	
9.	POH	0.0	0.0	192.0	24.0	0.0	0.0	
10.	FOH & EFOH	13.0	12.0	10.0	5.0	8.0	13.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	288.0	0.0	
12.	Oper MBtu	1231376	590856	1092048	896475	158561	1729070	
13.	Net Gen (MWH)	103651.2	49058.1	92148.2	76062.7	13744.9	153490.4	
14.	ANOHR (Btu/KWH)	11880.0	12044.0	11851.0	11786.0	11536.0	11265.0	
15.	NOF %	37.1	31.3	40.3	34.4	38.0	43.2	
16.	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

ESTIMATED 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 (%)	98.3	98.3	80.0	0.0	0.0	64.5	70.9
2.	POF (%)	0.0	0.0	16.7	100.0	100.0	35.5	23.5
3.	EUOF (%)	1.7	1.7	3.3	0.0	0.0	0.0	4.6
4.	EUOR (%)	2.3	1.7	11.5	0.0	0.0	0.0	9.1
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	544.0	731.0	184.0	0.0	0.0	0.0	4002.0
7.	RSH	187.0	0.0	392.0	0.0	0.0	480.0	2318.0
8.	UH	13.0	13.0	144.0	744.0	721.0	264.0	2464.0
9.	POH	0.0	0.0	120.0	744.0	721.0	264.0	2065.0
10.	FOH & EFOH	13.0	13.0	0.0	0.0	0.0	0.0	87.0
11.	MOH & EMOH	0.0	0.0	24.0	0.0	0.0	0.0	312.0
12.	Oper MBtu	1472162	1995347	513103	0	0	0	9678998
13.	Net Gen (MWH)	133179.1	180787.1	46650.0	0.0	0.0	0.0	848771.7
14.	ANOHR (Btu/KWH)	11054.0	11037.0	10999.0	-	-	-	11404.0
15.	NOF %	48.8	49.3	50.5	0.0	0.0	0.0	42.2
16.	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

ESTIMATED 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 (%)	97.4	97.4	78.6	30.0	48.4	96.7	
2.	POF (%)	0.0	0.0	0.0	70.0	51.6	0.0	
3.	EUOF (%)	2.6	2.6	21.4	0.0	0.0	3.3	
4.	EUOR (%)	3.6	4.8	100.0	0.0	0.0	4.0	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	506.0	360.0	0.0	137.0	271.0	578.0	
7.	RSH	219.0	318.0	584.0	79.0	89.0	118.0	
8.	UH	19.0	18.0	159.0	504.0	384.0	24.0	
9.	POH	0.0	0.0	0.0	504.0	384.0	0.0	
10.	FOH & EFOH	19.0	18.0	15.0	0.0	0.0	24.0	
11.	MOH & EMOH	0.0	0.0	144.0	0.0	0.0	0.0	
12.	Oper MBtu	1177958	754268	0	391255	614947	1575657	
13.	Net Gen (MWH)	103574.9	71454.0	0.0	35714.8	55621.1	142709.7	
14.	ANOHR (Btu/KWH)	11373.0	10556.0	-	10955.0	11056.0	11041.0	
15.	NOF %	40.8	39.5	0.0	51.9	40.9	49.2	
16.	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

ESTIMATED 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 (%)	96.6	96.9	97.5	97.4	81.3	97.6	84.7
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	10.1
3.	EUOF (%)	3.4	3.1	2.5	2.6	18.7	2.4	5.2
4.	EUOR (%)	3.7	3.2	2.6	3.2	100.0	2.9	8.3
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	652.0	686.0	687.0	576.0	0.0	596.0	5049.0
7.	RSH	67.0	35.0	15.0	149.0	586.0	130.0	2389.0
8.	UH	25.0	23.0	18.0	19.0	135.0	18.0	1346.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	888.0
10.	FOH & EFOH	25.0	23.0	18.0	19.0	15.0	18.0	194.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	120.0	0.0	264.0
12.	Oper MBtu	2001460	2075210	1920410	1465734	0	1342157	13319056
13.	Net Gen (MWH)	181308.0	191140.3	174678.0	131138.5	0.0	117188.3	1204527.4
14.	ANOHR (Btu/KWH)	11039.0	10857.0	10994.0	11177.0	-	11453.0	11057.0
15.	NOF %	55.4	55.5	50.6	45.4	0.0	39.2	47.5
16.	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

ESTIMATED 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 (%)	99.3	99.3	80.1	83.3	80.6	99.3	
2.	POF (%)	0.0	0.0	0.0	10.0	19.4	0.0	
3.	EUOF (%)	0.7	0.7	19.9	6.7	0.0	0.7	
4.	EUOR (%)	0.8	0.8	20.4	7.7	0.0	0.7	
5.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
6.	SH	660.0	639.0	579.0	578.0	583.0	676.0	
7.	RSH	79.0	52.0	16.0	22.0	17.0	39.0	
8.	UH	5.0	5.0	148.0	120.0	144.0	5.0	
9.	POH	0.0	0.0	0.0	72.0	144.0	0.0	
10.	FOH & EFOH	5.0	5.0	4.0	0.0	0.0	5.0	
11.	MOH & EMOH	0.0	0.0	144.0	48.0	0.0	0.0	
12.	Oper MBtu	2656477	2487941	2425208	2428870	2433438	2717563	
13.	Net Gen (MWH)	386452.8	365443.7	353322.9	353907.8	354470.2	395339.3	
14.	ANOHR (Btu/KWH)	6874.0	6808.0	6864.0	6863.0	6865.0	6874.0	
15.	NOF %	90.6	88.5	95.9	96.3	95.6	93.2	
16.	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

ESTIMATED 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 (%)	99.3	99.3	56.3	89.8	92.8	99.3	89.9
2.	POF (%)	0.0	0.0	43.3	9.7	0.0	0.0	6.8
3.	EUOF (%)	0.7	0.7	0.4	0.5	7.2	0.7	3.2
4.	EUOR (%)	0.7	0.7	0.7	0.6	7.4	0.7	3.6
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
6.	SH	732.0	706.0	399.0	662.0	650.0	677.0	7541.0
7.	RSH	7.0	33.0	6.0	6.0	19.0	62.0	358.0
8.	UH	5.0	5.0	315.0	76.0	52.0	5.0	885.0
9.	POH	0.0	0.0	312.0	72.0	0.0	0.0	600.0
10.	FOH & EFOH	5.0	5.0	3.0	4.0	4.0	5.0	45.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	48.0	0.0	240.0
12.	Oper MBtu	3031067	2960417	1639831	2735145	2737505	2737597	30991059
13.	Net Gen (MWH)	433381.0	421591.8	235913.0	404427.8	388629.4	398369.8	4491249.5
14.	ANOHR (Btu/KWH)	6994.0	7022.0	6951.0	6763.0	7044.0	6872.0	6900.0
15.	NOF %	94.4	95.2	94.3	96.1	94.0	91.0	93.7
16.	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

Issued by: Gulf Power Company

Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2020 - December 2020

Plant & Unit	Planned Outage Dates			Reason for Outage
Crist 7	03/07/20	-	04/26/20	Boiler outage
Smith 3	04/28/20	-	05/06/20	Borescope inspection
Smith 3	09/18/20	-	10/03/20	Borescope inspection
Daniel 1	03/24/20	-	04/01/20	Scrubber duct inspection
Daniel 1	09/26/20	-	12/11/20	Boiler outage
Daniel 2	04/10/20	-	05/17/20	Boiler outage

TAMPA ELECTRIC COMPANY

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 61
PARTY: TAMPA ELECTRIC COMPANY –
(DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-1

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

INDEX

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EXHIBIT TO THE TESTIMONY OF
PENELOPE A. RUSK

DOCUMENT NO. 1

FINAL CAPACITY OVER/(UNDER)RECOVERY FOR
JANUARY 2018 – DECEMBER 2018

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

1.	Actual End-of-Period True-up: Over/(Under) Recovery	($5,458,886)
2.	Actual Under Recovery per Mid-Course filed 1/15/19 (Exhibit D, Page 5, Line 13)	(5,458,886)
3.	Final True-up: Over/(Under) Recovery to Be Carried Forward to the January 2020 Through December 2020 Period	**$0**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Actual Jul-18	Actual Aug-18	Actual Sep-18	Actual Oct-18	Actual Nov-18	Actual Dec-18	Total
1 UNIT POWER CAPACITY CHARGES	0	0	0	0	0	0	0	0	0	0	0	0	0
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	1,033,633	927,808	842,124	905,476	1,224,568	1,276,897	1,274,398	1,358,180	1,338,480	1,301,772	897,269	847,079	13,227,684
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0	0	0	0	0	0	0	0	0	0
5 (CAPACITY REVENUES)	(449,731)	(54,848)	(174,015)	(265,506)	(150,282)	(134,875)	(90,928)	(106,910)	(89,496)	(96,920)	(41,393)	(101,012)	(1,755,916)
6 TOTAL CAPACITY DOLLARS	583,902	872,960	668,109	639,970	1,074,286	1,142,022	1,183,470	1,251,270	1,248,984	1,204,852	855,876	746,067	11,471,768
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	
8 JURISDICTIONAL CAPACITY DOLLARS	583,902	872,960	668,109	639,970	1,074,286	1,142,022	1,183,470	1,251,270	1,248,984	1,204,852	855,876	746,067	11,471,768
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	869,605	795,335	768,043	763,069	812,583	940,249	1,044,781	1,027,112	1,108,445	1,021,640	886,813	786,156	10,823,831
10 PRIOR PERIOD TRUE-UP PROVISION	(230,245)	(230,245)	(230,245)	(230,245)	(230,245)	(230,245)	(230,245)	(230,245)	(230,245)	(230,245)	(230,245)	(230,243)	(2,762,938)
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	639,360	565,090	537,798	532,824	582,338	710,004	814,536	796,867	878,200	791,395	656,568	555,913	8,060,893
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	55,458	(307,870)	(130,311)	(107,146)	(491,948)	(432,018)	(368,934)	(454,403)	(370,784)	(413,457)	(199,308)	(190,154)	(3,410,875)
13 INTEREST PROVISION FOR PERIOD	(5,807)	(5,727)	(6,479)	(6,763)	(6,881)	(7,485)	(8,012)	(8,325)	(9,163)	(10,111)	(10,437)	(10,772)	(95,962)
14 OTHER ADJUSTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
15 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(4,714,987)	(4,435,091)	(4,518,443)	(4,424,988)	(4,308,652)	(4,577,236)	(4,786,494)	(4,933,195)	(5,165,678)	(5,315,380)	(5,508,703)	(5,488,203)	(4,714,987)
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	230,245	230,245	230,245	230,245	230,245	230,245	230,245	230,245	230,245	230,245	230,245	230,243	2,762,938
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	(4,435,091)	(4,518,443)	(4,424,988)	(4,308,652)	(4,577,236)	(4,786,494)	(4,933,195)	(5,165,678)	(5,315,380)	(5,508,703)	(5,488,203)	(5,458,886)	**(5,458,886)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Actual Jul-18	Actual Aug-18	Actual Sep-18	Actual Oct-18	Actual Nov-18	Actual Dec-18	Total
1 BEGINNING TRUE-UP AMOUNT	(4,714,987)	(4,435,091)	(4,518,443)	(4,424,988)	(4,308,652)	(4,577,236)	(4,786,494)	(4,933,195)	(5,165,678)	(5,315,380)	(5,508,703)	(5,488,203)	(4,714,987)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(4,429,284)	(4,512,716)	(4,418,509)	(4,301,889)	(4,570,355)	(4,779,009)	(4,925,183)	(5,157,353)	(5,306,217)	(5,498,592)	(5,477,766)	(5,448,114)	(5,362,924)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(9,144,271)	(8,947,807)	(8,936,952)	(8,726,877)	(8,879,007)	(9,356,245)	(9,711,677)	(10,090,548)	(10,471,895)	(10,813,972)	(10,986,469)	(10,936,317)	(10,077,911)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(4,572,136)	(4,473,904)	(4,468,476)	(4,363,439)	(4,439,504)	(4,678,123)	(4,855,839)	(5,045,274)	(5,235,948)	(5,406,986)	(5,493,235)	(5,468,159)	(5,038,956)
5 INTEREST RATE % - 1ST DAY OF MONTH	1.580	1.460	1.620	1.860	1.850	1.860	1.980	1.980	1.980	2.210	2.270	2.300	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	1.460	1.620	1.860	1.850	1.860	1.980	1.980	1.980	2.210	2.270	2.300	2.420	NA
7 TOTAL (LINE 5 + LINE 6)	3.040	3.080	3.480	3.710	3.710	3.840	3.960	3.960	4.190	4.480	4.570	4.720	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	1.520	1.540	1.740	1.855	1.855	1.920	1.980	1.980	2.095	2.240	2.285	2.360	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.127	0.128	0.145	0.155	0.155	0.160	0.165	0.165	0.175	0.187	0.190	0.197	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(5,807)	(5,727)	(6,479)	(6,763)	(6,881)	(7,485)	(8,012)	(8,325)	(9,163)	(10,111)	(10,437)	(10,772)	(95,962)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

	(1) ACTUAL	(2) ACTUAL PER MID-COURSE	(3) VARIANCE (1) - (2)	(4) % CHANGE (3)/(2)
1 UNIT POWER CAPACITY CHARGES	$0	$0	$0	0.00%
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0.00%
3 SCHEDULE J & D CAPACITY CHARGES	13,227,684	13,227,684	0	0.00%
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0.00%
5 (CAPACITY REVENUES)	(1,755,916)	(1,755,916)	0	0.00%
6 TOTAL CAPACITY DOLLARS	$11,471,768	$11,471,768	$0	0.00%
7 JURISDICTIONAL PERCENTAGE	100.00%	100.00%	0	0.00%
8 JURISDICTIONAL CAPACITY DOLLARS	$11,471,768	11,471,768	$0	0.00%
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	10,823,831	10,823,831	0	0.00%
10 PRIOR PERIOD TRUE-UP PROVISION	(2,762,938)	(2,762,938)	0	0.00%
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	$8,060,893	$8,060,893	$0	0.00%
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	($3,410,875)	($3,410,875)	$0	0.00%
13 INTEREST PROVISION FOR PERIOD	(95,962)	(95,962)	0	0.00%
14 OTHER ADJUSTMENT	0	0	0	0.00%
15 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(4,714,987)	(4,714,987)	0	0.00%
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	2,762,938	2,762,938	0	0.00%
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	($5,458,886)	($5,458,886)	$0	0.00%

EXHIBIT TO THE TESTIMONY OF
PENELOPE A. RUSK

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/(UNDER)RECOVERY
FOR
JANUARY 2018 – DECEMBER 2018

TAMPA ELECTRIC COMPANY
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2018 THROUGH DECEMBER 2018

1 TOTAL FUEL COSTS FOR THE PERIOD	$673,683,598
2 JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	673,683,598
3 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	629,844,306
4 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD (LINE 3 - LINE 2)	($43,839,292)
5 ADJUSTMENTS *	(144,678)
6 INTEREST	(186,849)
7 TRUE-UP COLLECTED	(17,081,137)
8 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/17)	24,281,044
9 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7 + LINE 8)	($36,970,912)
10 PROJECTED OVER-RECOVERY PER PROJECTION FILED 8/24/18 (SCHEDULE E1-A LINE 3)	7,015,485
11 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 9 - LINE 10)	**($43,986,397)**

* Includes January adj of ($190,412) for Big Bend Unit 2 outage replacement power cost true-up, February adj of $2,670 for Dec 2017 interest on Big Bend Unit 2 outage replacement power cost, and May adj of $43,064 related to Jan-Apr 2018 Big Bend and Polk assets for tax reform.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

ORIGINAL ESTIMATES

JANUARY 2018 – DECEMBER 2018

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. ORIGINAL ESTIMATES
FOR THE PERIOD
JANUARY 2018 THROUGH DECEMBER 2018

		ACTUAL	ESTIMATED	VARIANCE AMOUNT	%
A	1. FUEL COST OF SYSTEM NET GENERATION	$631,710,782	$606,993,585	$24,717,197	4.1
	2. FUEL COST OF POWER SOLD	7,357,519	631,976	6,725,543	1,064.2
	2a. GAINS FROM SALES	2,607,475	54,591	2,552,884	4,676.4
	3. FUEL COST OF PURCHASED POWER	4,834,769	2,681,380	2,153,389	80.3
	3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	3b. PAYMENT TO QUALIFIED FACILITIES	4,835,472	2,579,410	2,256,062	87.5
	4. ENERGY COST OF ECONOMY PURCHASES	35,800,487	9,706,470	26,094,017	268.8
	6a. ADJ. - BIG BEND UNITS 1-4 IGNITERS CONVERSION PROJECT	4,816,753	4,877,765	(61,012)	(1.3)
	6b. ADJ. - POLK 1 CONVERSION DEPRECIATION & ROI	1,650,329	1,650,886	(557)	0.0
	6c. ADJ. - POLK WARM GAS CLEANUP	0	0	0	0.0
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. (SUM OF LINES A1 THRU 6c)	$673,683,598	$627,802,929	$45,880,669	7.3
C	1. JURISDICTIONAL FUEL REVENUE	$612,810,561	$610,214,478	$2,596,083	0.4
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0
	2a. TRUE-UP PROVISION	17,081,137	17,081,137	0	0.0
	2b. INCENTIVE PROVISION	(47,392)	(47,392)	0	0.0
	2c. ADJUSTMENT	0	0	0	0.0
	3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2c)	$629,844,306	$627,248,223	$2,596,083	0.4
	6d.JURISD. TOTAL FUEL & NET PWR. TRANS.	673,683,598	627,802,929	45,880,669	7.3
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6d)	($43,839,292)	($554,706)	($43,284,586)	7,803.2
	7a. ADJUSTMENTS *	(144,678)	0	(144,678)	0.0
	8. INTEREST PROVISION - THIS PERIOD	(186,849)	20,812	(207,661)	(997.8)
	TOTAL TRUE-UP AMOUNT FOR PERIOD (LINE 7 through 8)	($44,170,819)	($533,894)	($43,636,925)	8,173.3
	9.TRUE-UP & INT. PROV. BEG. OF PERIOD (Beginning January 2018)	24,281,044	17,081,137	7,199,907	42.2
	10.TRUE-UP COLLECTED (REFUNDED)	(17,081,137)	(17,081,137)	0	0.0
	11.END OF PERIOD TOTAL NET TRUE-UP (LINE C8 through C10)	($36,970,912)	($533,894)	($36,437,018)	6,824.8

* Includes January adj of ($190,412) for Big Bend Unit 2 outage replacement power cost true-up, February adj of $2,670 for Dec 2017 interest on Big Bend Unit 2 outage replacement power cost, and May adj of $43,064 related to Jan-Apr 2018 Big Bend and Polk assets for tax reform.
Line numbers reference Schedule A-2 included in Document No. 4

EXHIBIT TO THE TESTIMONY OF
PENELOPE A. RUSK

DOCUMENT NO. 4

FUEL AND PURCHASED POWER COST RECOVERY
YTD DECEMBER 2018

SCHEDULES A1 AND A2
AND
SCHEDULES A6 THROUGH A9
AND
SCHEDULE A12

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 AND A2

DECEMBER 2018

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: December 2018

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	58,547,213	45,007,983	13,539,230	30.1%	1,455,938	1,500,700	(44,762)	-3.0%	4.02127	2.99913	1.02214	34.1%
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	386,031	392,424	(6,393)	-1.6%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments - Polk 1 Conversion Depreciation & ROI	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)	**58,933,244**	**45,400,407**	**13,532,837**	**29.8%**	**1,455,938**	**1,500,700**	**(44,762)**	**-3.0%**	**4.04779**	**3.02528**	**1.02250**	**33.8%**
6. Fuel Cost of Purchased Power - Firm (A7)	154,188	137,590	16,598	12.1%	2,866	3,190	(324)	-10.2%	5.37990	4.31317	1.06674	24.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	113,100	710,560	(597,460)	-84.1%	2,180	27,380	(25,200)	-92.0%	5.18807	2.59518	2.59289	99.9%
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)	791,694	189,800	601,894	317.1%	27,850	7570	20,280	267.9%	2.84271	2.50727	0.33544	13.4%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**1,058,982**	**1,037,950**	**21,032**	**2.0%**	**32,896**	**38,140**	**(5,244)**	**-13.7%**	**3.21918**	**2.72142**	**0.49776**	**18.3%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,488,834**	**1,538,840**	**(50,006)**	**-3.2%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	104,178	14,820	89,358	603.0%	3,970	590	3,380	572.9%	2.62413	2.51186	0.11227	4.5%
15. Fuel Cost of Sch. C/CB Sales (A6)	11,616	0	11,616	0.0%	468	0	468	0.0%	2.48205	0.00000	2.48205	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)	223,282	29,261	194,021	663.1%	7,734	1170	6,564	561.0%	2.88702	2.50094	0.38608	15.4%
18. Gains on Sales	83,341	3,937	79,404	2016.9%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES	**422,417**	**48,018**	**374,399**	**779.7%**	**12,172**	**1,760**	**10,412**	**591.6%**	**3.47040**	**2.72830**	**0.74210**	**27.2%**
(LINE 14 + 15 + 16 + 17 + 18)												
20. Net Inadvertant Interchange					137	0	137	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					952	0	952	0.0%				
22. Interchange and Wheeling Losses					1,235	-43.005	1,278	-2971.8%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS	**59,569,809**	**46,390,339**	**13,179,470**	**28.4%**	**1,476,516**	**1,537,123**	**(60,607)**	**-3.9%**	**4.03448**	**3.01800**	**1.01649**	**33.7%**
(LINE 5 + 12 - 19 + 20 + 21 - 22)												
24. Net Unbilled	680,618 (a)	1,779,623 (a)	(1,099,005)	-61.8%	16,870	58,967	(42,097)	-71.4%	4.03449	3.01800	1.01649	33.7%
25. Company Use	117,605 (a)	87,522 (a)	30,083	34.4%	2,915	2,900	15	0.5%	4.03448	3.01800	1.01648	33.7%
26. T & D Losses	1,637,073 (a)	1,202,582 (a)	434,491	36.1%	40,577	39,847	730	1.8%	4.03449	3.01800	1.01649	33.7%
27. System KWH Sales	59,569,809	46,390,339	13,179,470	28.4%	1,416,154	1,435,409	(19,255)	-1.3%	4.20645	3.23186	0.97459	30.2%
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	59,569,809	46,390,339	13,179,470	28.4%	1,416,154	1,435,409	(19,255)	-1.3%	4.20645	3.23186	0.97459	30.2%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	59,569,809	46,390,339	13,179,470	28.4%	1,416,154	1,435,409	(19,255)	-1.3%	4.20645	3.23186	0.97459	30.2%
32. Adjustment - Jan thru Apr 2018 Adj for Big Bend and Polk Assets Due to Tax Reform Including Interest	0	0	0	0.0%	1,416,154	1,435,409	(19,255)	-1.3%	0.00000	0.00000	0.00000	0.0%
33. True-up *	(1,423,429)	(1,423,429)	0	0.0%	1,416,154	1,435,409	(19,255)	-1.3%	(0.10051)	(0.09917)	(0.00135)	1.4%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	58,146,380	44,966,910	13,179,470	29.3%	1,416,154	1,435,409	(19,255)	-1.3%	4.10594	3.13269	0.97325	31.1%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	58,188,245	44,999,286	13,188,959	29.3%	1,416,154	1,435,409	(19,255)	-1.3%	4.10889	3.13495	0.97394	31.1%
37. GPIF * (Already Adjusted for Taxes)	3,953	3,953	0	0.0%	1,416,154	1,435,409	(19,255)	-1.3%	0.00028	0.00028	0.00000	1.4%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**58,192,198**	**45,003,239**	**13,188,959**	**29.3%**	**1,416,154**	**1,435,409**	**(19,255)**	**-1.3%**	**4.10917**	**3.13523**	**0.97394**	**31.1%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**4.109**	**3.135**	**0.974**	**31.1%**

* 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 2018

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	631,710,782	606,993,585	24,717,197	4.1%	19,748,460	20,067,160	(318,700)	-1.6%	3.19879	3.02481	0.17397	5.8%
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	4,816,753	4,877,765	(61,012)	-1.3%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments - Polk 1 Conversion Depreciation & ROI	1,650,329	1,650,886	(557)	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)	**638,177,864**	**613,522,236**	**24,655,628**	**4.0%**	**19,748,460**	**20,067,160**	**(318,700)**	**-1.6%**	**3.23153**	**3.05734**	**0.17419**	**5.7%**
6. Fuel Cost of Purchased Power - Firm (A7)	4,834,769	2,681,380	2,153,389	80.3%	96,543	67,450	29,093	43.1%	5.00789	3.97536	1.03253	26.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	35,800,487	9,706,470	26,094,017	268.8%	931,538	313,280	618,258	197.3%	3.84316	3.09834	0.74482	24.0%
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)	4,835,472	2,579,410	2,256,062	87.5%	194,359	90,110	104,249	115.7%	2.48791	2.86251	(0.37461)	-13.1%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**45,470,728**	**14,967,260**	**30,503,468**	**203.8%**	**1,222,440**	**470,840**	**751,600**	**159.6%**	**3.71967**	**3.17884**	**0.54083**	**17.0%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**20,970,900**	**20,538,000**	**432,900**	**2.1%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	655,905	270,150	385,755	142.8%	28,413	10,340	18,073	174.8%	2.30847	2.61267	(0.30420)	-11.6%
15. Fuel Cost of Sch. C/CB Sales (A6)	118,326	0	118,326	0.0%	6,384	0	6,384	0.0%	1.85348	0.00000	1.85348	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)	6,583,288	361,826	6,221,462	1719.5%	251,357	11,990	239,367	1996.4%	2.61910	3.01773	(0.39863)	-13.2%
18. Gains on Sales	2,607,475	54,591	2,552,884	4676.4%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES	**9,964,994**	**686,567**	**9,278,427**	**1351.4%**	**286,154**	**22,330**	**263,824**	**1181.5%**	**3.48239**	**3.07464**	**0.40775**	**13.3%**
(LINE 14 + 15 + 16 + 17 + 18)												
20. Net Inadvertant Interchange					(16)	0	(16)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					44,331	0	44,331	0.0%				
22. Interchange and Wheeling Losses					50,357	(598)	50,955	-8522.9%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS	**673,683,598**	**627,802,929**	**45,880,669**	**7.3%**	**20,678,704**	**20,516,268**	**162,436**	**0.8%**	**3.25786**	**3.06003**	**0.19784**	**6.5%**
(LINE 5 + 12 - 19 + 20 + 21 - 22)												
24. Net Unbilled	(767,327) (a)	139,715 (a)	(907,042)	-649.2%	(17,446)	13,963	(31,409)	-224.9%	4.39830	1.00061	3.39769	339.6%
25. Company Use	1,270,723 (a)	1,070,539 (a)	200,184	18.7%	38,863	34,800	4,063	11.7%	3.26975	3.07626	0.19349	6.3%
26. T & D Losses	33,158,832 (a)	28,151,540 (a)	5,007,292	17.8%	1,025,823	923,386	102,437	11.1%	3.23241	3.04873	0.18368	6.0%
27. System KWH Sales	673,683,598	627,802,929	45,880,669	7.3%	19,631,464	19,544,119	87,345	0.4%	3.43165	3.21223	0.21942	6.8%
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	673,683,598	627,802,929	45,880,669	7.3%	19,631,464	19,544,119	87,345	0.4%	3.43165	3.21223	0.21942	6.8%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	673,683,598	627,802,929	45,880,669	7.3%	19,631,464	19,544,119	87,345	0.4%	3.43165	3.21223	0.21942	6.8%
32. Adjustments - Schedule A2, page 2, lines 6c, 7a and 8b	147,348	0	147,348	0.0%	19,631,464	19,544,119	87,345	0.4%	0.00075	0.00000	0.00075	0.0%
33. True-up *	(17,081,137)	(17,081,137)	0	0.0%	19,631,464	19,544,119	87,345	0.4%	(0.08701)	(0.08740)	0.00039	-0.4%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	656,749,809	610,721,792	46,028,017	7.5%	19,631,464	19,544,119	87,345	0.4%	3.34539	3.12484	0.22056	7.1%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	657,222,668	611,161,511	46,061,157	7.5%	19,631,464	19,544,119	87,345	0.4%	3.34780	3.12709	0.22071	7.1%
37. GPIF * (Already Adjusted for Taxes)	47,392	47,392	0	0.0%	19,631,464	19,544,119	87,345	0.4%	0.00024	0.00024	(0.00000)	-0.4%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**657,270,060**	**611,208,903**	**46,061,157**	**7.5%**	**19,631,464**	**19,544,119**	**87,345**	**0.4%**	**3.34804**	**3.12733**	**0.22071**	**7.1%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.348**	**3.127**	**0.221**	**7.1%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2018

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	58,547,213	45,007,983	13,539,230	30.1%	631,710,782	606,993,585	24,717,197	4.1%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	339,076	44,081	294,995	669.2%	7,357,519	631,976	6,725,543	1064.2%
2a. GAINS FROM SALES	83,341	3,937	79,404	2016.9%	2,607,475	54,591	2,552,884	4676.4%
3. FUEL COST OF PURCHASED POWER	154,188	137,590	16,598	12.1%	4,834,769	2,681,380	2,153,389	80.3%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	791,694	189,800	601,894	317.1%	4,835,472	2,579,410	2,256,062	87.5%
4. ENERGY COST OF ECONOMY PURCHASES	113,100	710,560	(597,460)	-84.1%	35,800,487	9,706,470	26,094,017	268.8%
5. TOTAL FUEL & NET POWER TRANSACTION	59,183,778	45,997,915	13,185,863	28.7%	667,216,516	621,274,278	45,942,238	7.4%
6a. ADJ. - BIG BEND UNITS 1-4 IGNITERS CONVERSION PROJECT	386,031	392,424	(6,393)	-1.6%	4,816,753	4,877,765	(61,012)	-1.3%
6b. ADJ. - POLK 1 CONVERSION DEPRECIATION & ROI	0	0	0	0.0%	1,650,329	1,650,886	(557)	0.0%
6c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	59,569,809	46,390,339	13,179,470	28.4%	673,683,598	627,802,929	45,880,669	7.3%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,416,154	1,435,409	(19,255)	-1.3%	19,631,464	19,544,119	87,345	0.4%
2. NONJURISDICTIONAL SALES	0	0	0	0.0%	0	0	0	0.0%
3. TOTAL SALES	1,416,154	1,435,409	(19,255)	-1.3%	19,631,464	19,544,119	87,345	0.4%
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 2018

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	43,501,078	44,134,193	(633,115)	-1.4%	612,810,561	610,214,478	2,596,083	0.4%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	1,423,429	1,423,429	0	0.0%	17,081,137	17,081,137	0	0.0%
2b. GPIF PROVISION	(3,953)	(3,953)	0	0.0%	(47,392)	(47,392)	0	0.0%
2c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	44,920,554	45,553,669	(633,115)	-1.4%	629,844,306	627,248,223	2,596,083	0.4%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	59,569,809	46,390,339	13,179,470	28.4%	673,683,598	627,802,929	45,880,669	7.3%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	1.0000000	1.0000000	0.0000000	0.0%	-	-	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	59,569,809	46,390,339	13,179,470	28.4%	673,683,598	627,802,929	45,880,669	7.3%
6a. JURISDIC. LOSS MULTIPLIER	1.00000	1.00000	0.00000	0.0%	-	-	-	-
6b. (LINE C6 x LINE C6a)	59,569,809	46,390,339	13,179,470	28.4%	673,683,598	627,802,929	45,880,669	7.3%
6c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
6d. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6c)	59,569,809	46,390,339	13,179,470	28.4%	673,683,598	627,802,929	45,880,669	7.3%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6d)	(14,649,255)	(836,670)	(13,812,585)	1650.9%	(43,839,292)	(554,706)	(43,284,586)	7803.2%
7a. ADJ-BB UNIT 2 OUTAGE REPLACEMENT POWER COST T-Up	0	0	0	0.0%	(190,412)	0	(190,412)	0.0%
8. INTEREST PROVISION FOR THE MONTH	(56,889)	1,089	(57,978)	-5324.0%	(186,849)	20,812	(207,661)	-997.8%
8a. ADJ-DEC 2017 INTEREST ADJUSTMENT FOR BB UNIT 2 OUTAGE REPLACEMENT POWER COST	0	0	0	0.0%	2,670	0	2,670	0.0%
8b. ADJ - JAN THRU APR 2018 ADJUSTMENT FOR BIG BEND AND POLK ASSETS DUE TO TAX REFORM INCLUDING INTEREST	0	0	0	0.0%	43,064	0	43,064	0.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(20,841,339)	1,725,116	(22,566,455)	-1308.1%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED (REFUNDED)	(1,423,429)	(1,423,429)	0	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(36,970,912)	(533,894)	(36,437,018)	6824.8%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2018

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(20,841,339)	1,725,116	(22,566,455)	-1308.1%	----------NOT APPLICABLE----------			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(36,914,023)	(534,983)	(36,379,040)	6800.0%	----------NOT APPLICABLE----------			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(57,755,362)	1,190,133	(58,945,495)	-4952.8%	----------NOT APPLICABLE----------			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(28,877,681)	595,067	(29,472,748)	-4952.8%	----------NOT APPLICABLE----------			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	2.300	2.200	0.100	4.5%	----------NOT APPLICABLE----------			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	2.420	2.200	0.220	10.0%	----------NOT APPLICABLE----------			
7. TOTAL (LINE D5 + LINE D6)	4.720	4.400	0.320	7.3%	----------NOT APPLICABLE----------			
8. AVERAGE INT. RATE (50% OF LINE D7)	2.360	2.200	0.160	7.3%	----------NOT APPLICABLE----------			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.197	0.183	0.014	7.7%	----------NOT APPLICABLE----------			
10. INT. PROVISION (LINE D4 x LINE D9)	(56,889)	1,089	(57,978)	-5324.0%	----------NOT APPLICABLE----------			

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2018 - DECEMBER 2018

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)		(3)	(4)	(5)	(6)		(7)	(8)	(9)
						CENTS/KWH				
SOLD TO	TYPE & SCHEDULE		TOTAL MWH SOLD	MWH WHEELED OTHER SYSTEM	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	TOTAL $ FOR TOTAL COST (5)X(6B)	GAINS ON MARKET BASED SALES
ESTIMATED:										
SEMINOLE	JURISD.	SCH. - D	10,340.0	0.0	10,340.0	2.613	2.790	270,150.00	288,517.00	18,367.00
VARIOUS	JURISD.	MKT.BASE	11,990.0	0.0	11,990.0	3.018	3.320	361,827.45	398,050.00	36,222.55
TOTAL			**22,330.0**	**0.0**	**22,330.0**	**2.830**	**3.075**	**631,977.45**	**686,567.00**	**54,589.55**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISD.	SCH. - D	28,431.0	18.0	28,413.0	2.308	2.539	655,906.07	721,496.67	33,036.89
REEDY CREEK		SCH. - CB	6,384.0	0.0	6,384.0	1.853	2.139	118,324.68	136,526.87	13,546.36
EXGEN		SCH. - MA	21,175.0	0.0	21,175.0	2.856	4.602	604,698.57	974,491.76	320,625.32
FLORIDA POWER & LIGHT		SCH. - MA	6,470.0	0.0	6,470.0	2.788	4.070	180,410.00	263,352.85	71,681.40
DUKE ENERGY FLORIDA		SCH. - MA	37,660.0	0.0	37,660.0	2.332	3.263	878,101.60	1,229,009.54	310,022.94
CITY OF LAKELAND		SCH. - MA	72,600.0	0.0	72,600.0	2.473	3.096	1,795,722.00	2,247,868.40	338,668.40
NEW SMYRNA BEACH		SCH. - MA	182.0	0.0	182.0	2.996	4.538	5,452.29	8,259.19	2,565.55
ORLANDO UTILITIES		SCH. - MA	10,917.0	0.0	10,917.0	2.385	3.582	260,393.51	391,018.71	116,683.71
REEDY CREEK		SCH. - MA	1,530.0	0.0	1,530.0	1.612	2.227	24,665.80	34,067.00	8,821.40
SOUTHERN COMPANY		SCH. - MA	14,034.0	0.0	14,034.0	2.946	4.249	413,463.82	596,305.89	175,969.29
THE ENERGY AUTHORITY		SCH. - MA	58,681.0	0.0	58,681.0	2.579	3.940	1,513,238.63	2,312,133.36	715,960.17
EDF TRADING		SCH. - MA	7,489.0	0.0	7,489.0	3.495	5.454	261,753.80	408,438.53	130,663.12
MORGAN STANLEY		SCH. - MA	5,617.0	0.0	5,617.0	3.160	5.045	177,522.34	283,356.67	97,439.14
MACQUARIE ENERGY LLC		SCH. - MA	15,002.0	0.0	15,002.0	3.119	5.011	467,866.89	751,720.52	271,790.31
LESS 20% - THRESHOLD EXCESS		SCH. - D								0.00
LESS 20% - THRESHOLD EXCESS		SCH. - C								0.00
LESS 20% - THRESHOLD EXCESS		SCH. - CB								0.00
LESS 20% - THRESHOLD EXCESS		SCH. - MA								0.00
SUB-TOTAL			**286,172.0**	**18.0**	**286,154.0**	**2.571**	**3.620**	**7,357,520.00**	**10,358,045.96**	**2,607,474.00**
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			28,431.0	18.0	28,413.0	2.308	2.539	655,906.07	721,496.67	33,036.89
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			6,384.0	0.0	6,384.0	1.853	2.139	118,324.68	136,526.87	13,546.36
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			251,357.0	0.0	251,357.0	2.619	3.779	6,583,289.25	9,500,022.42	2,560,890.75
SUB-TOTAL OATT POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TOTAL			**286,172.0**	**18.0**	**286,154.0**	**2.571**	**3.620**	**7,357,520.00**	**10,358,045.96**	**2,607,474.00**
DIFFERENCE			263,842.0	18.0	263,824.0	(0.259)	0.545	6,725,542.55	9,671,478.96	2,552,884.45
DIFFERENCE %			1181.6%	0.0%	1181.5%	-9.2%	17.7%	1064.2%	1408.7%	4676.5%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2018 - DECEMBER 2018

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

(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:								
PASCO COGEN	SCH. - D	67,450.0	0.0	0.0	67,450.0	3.975	3.975	2,681,380.00
TOTAL		**67,450.0**	**0.0**	**0.0**	**67,450.0**	**3.975**	**3.975**	**2,681,380.00**
ACTUAL:								
PASCO COGEN	SCH. - D	88,525.0	0.0	0.0	88,525.0	5.172	5.172	4,578,433.33
DUKE ENERGY FLORIDA	OATT	8,070.0	0.0	0.0	8,070.0	3.210	3.210	259,011.51
CITY OF LAKELAND	OATT	(52.0)	0.0	0.0	(52.0)	5.144	5.144	(2,674.85)
SUB-TOTAL		**96,543.0**	**0.0**	**0.0**	**96,543.0**	**5.008**	**5.008**	**4,834,769.99**
SUB-TOTAL SCHEDULE D PURCHASED POWER		88,525.0	0.0	0.0	88,525.0	5.172	5.172	4,578,433.33
SUB-TOTAL SCHEDULE OATT PURCHASED POWER		8,018.0	0.0	0.0	8,018.0	3.197	3.197	256,336.66
TOTAL		**96,543.0**	**0.0**	**0.0**	**96,543.0**	**5.008**	**5.008**	**4,834,769.99**
DIFFERENCE		29,093.0	0.0	0.0	29,093.0	1.033	1.033	2,153,389.99
DIFFERENCE %		43.1%	0.0%	0.0%	43.1%	26.0%	26.0%	80.3%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2018 - DECEMBER 2018

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)	(7) CENTS/KWH		(8)
	TYPE	TOTAL	MWH FROM	MWH FOR	MWH	(A)	(B)	TOTAL $ FOR FUEL
ESTIMATED:								
VARIOUS	**COGEN.**							
	AS AVAIL.	90,110.0	0.0	0.0	90,110.0	2.863	2.863	2,579,410.00
TOTAL		**90,110.0**	**0.0**	**0.0**	**90,110.0**	**2.863**	**2.863**	**2,579,410.00**
ACTUAL:	**AS AVAILABLE**							
McKAY BAY REFUSE	COGEN.	58.0	0.0	0.0	58.0	2.358	2.358	1,367.71
CARGILL RIDGEWOOD	COGEN.	16,291.0	0.0	0.0	16,291.0	2.610	2.610	425,206.63
CARGILL MILLPOINT	COGEN.	21,780.0	0.0	0.0	21,780.0	2.517	2.517	548,180.11
IMC-AGRICO-NEW WALES	COGEN.	6,801.0	0.0	0.0	6,801.0	2.715	2.715	184,644.65
IMC-AGRICO-S. PIERCE	COGEN.	147,078.0	0.0	0.0	147,078.0	2.464	2.464	3,624,243.48
HILLSBOROUGH COUNTY	COGEN.	1.0	0.0	0.0	1.0	2.262	2.262	22.62
SUB-TOTAL COGEN		**192,009.0**	**0.0**	**0.0**	**192,009.0**	**2.491**	**2.491**	**4,783,665.20**
NET METERING		**2,350.8**	**0.0**	**0.0**	**2,350.8**	**2.204**	**2.204**	**51,805.81**
TOTAL INCL NET METERING		**194,359.8**	**0.0**	**0.0**	**194,359.8**	**2.488**	**2.488**	**4,835,471.01**
DIFFERENCE		104,249.8	0.0	0.0	104,249.8	(0.375)	(0.375)	2,256,061.01
DIFFERENCE %		115.7%	0.0%	0.0%	115.7%	-13.1%	-13.1%	87.5%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2018 - DECEMBER 2018

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR INTERRUP-TIBLE	(5) MWH FOR FIRM	(6) TRANSACTION COSTS CENTS/KWH	(7) TOTAL $ FOR FUEL ADJUSTMENT (5) X (6)	(8) COST IF GENERATED (A) CENTS PER KWH	(8) COST IF GENERATED (B) TOTAL COST	(9) FUEL SAVINGS (8B)-7
ESTIMATED:									
VARIOUS	Economy	313,280.0	0.0	313,280.0	3.098	9,706,470.00	4.921	15,417,030.00	5,710,560.00
TOTAL		**313,280.0**	**0.0**	**313,280.0**	**3.098**	**9,706,470.00**	**4.921**	**15,417,030.00**	**5,710,560.00**
ACTUAL:									
NEW HOPE/OKEELANTA	SCH. - REB	5.0	0.0	5.0	3.000	150.00	3.000	150.00	0.00
CITY OF LAKELAND	SCH. - J	2,000.0	0.0	2,000.0	7.290	145,800.00	7.290	145,800.00	0.00
CITY OF TALLAHASSEE	SCH. - J	80.0	0.0	80.0	1.000	800.00	1.921	1,536.80	736.80
DUKE ENERGY FLORIDA	SCH. - J	3,635.0	0.0	3,635.0	6.940	252,260.00	6.940	252,260.00	0.00
EDF TRADING	SCH. - J	2,720.0	0.0	2,720.0	2.883	78,415.00	3.176	86,381.45	7,966.45
EXGEN	SCH. - J	321,811.0	86.6	321,724.4	3.643	11,721,550.00	4.337	13,951,744.17	2,230,194.17
FLORIDA POWER & LIGHT	SCH. - J	538,375.0	255.6	538,119.4	3.677	19,786,975.35	4.118	22,158,149.55	2,371,174.20
FMPA	SCH. - J	528.0	0.0	528.0	45.000	237,600.00	45.000	237,600.00	0.00
MORGAN STANLEY	SCH. - J	4,765.0	0.0	4,765.0	5.258	250,521.00	5.499	262,021.00	11,500.00
ORLANDO UTIL. COMM.	SCH. - J	8,629.0	10.7	8,618.3	6.490	559,299.25	6.601	568,877.45	9,578.20
SOUTHERN COMPANY	SCH. - J	23,238.0	75.0	23,163.0	6.057	1,403,049.99	6.651	1,540,474.99	137,425.00
THE ENERGY AUTHORITY	SCH. - J	26,180.0	0.0	26,180.0	5.210	1,364,067.00	7.599	1,989,545.55	625,478.55
SUB-TOTAL		**931,965.9**	**427.8**	**931,538.1**	**3.843**	**35,800,487.59**	**4.422**	**41,194,540.96**	**5,394,053.37**
SUB-TOTAL SCHEDULE REB ECONOMY PURCHASES		5.0	0.0	5.0	3.000	150.00	3.000	150.00	0.00
SUB-TOTAL SCHEDULE J ECONOMY PURCHASES		931,960.9	427.8	931,533.1	3.843	35,800,337.59	4.422	41,194,390.96	5,394,053.37
TOTAL		**931,965.9**	**427.8**	**931,538.1**	**3.843**	**35,800,487.59**	**4.422**	**41,194,540.96**	**5,394,053.37**
DIFFERENCE		618,685.9	427.8	618,258.1	0.745	26,094,017.59	(0.499)	25,777,510.96	(316,506.63)
DIFFERENCE %		197.5%	0.0%	197.4%	24.0%	268.8%	-10.1%	167.2%	-5.5%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A12

JANUARY 2018 - DECEMBER 2018

REDACTED

REDACTED

SCHEDULE A12
PAGE 1 OF 1

CAPACITY COSTS
ACTUAL PURCHASES AND SALES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

CONTRACT	TERM START	TERM END	CONTRACT TYPE
PASCO COGEN LTD	1/1/2009	12/31/2018	LT
SEMINOLE ELECTRIC **	6/1/1992	----------	LT

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT-TERM
**** THREE YEAR NOTICE REQUIRED FOR TERMINATION.**

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
PASCO COGEN LTD	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
SEMINOLE ELECTRIC	10.3	7.1	5.9	5.6	0.9	1.9	2.1	2.3	2.1	8.9	2.1	7.8

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
PASCO COGEN LTD - D	[redacted]												
CITY OF TALLAHASSEE													
SEMINOLE ELECTRIC													
FLORIDA POWER & LIGHT													
DUKE ENERGY FLORIDA													
JACKSONVILLE ELECTRIC AUTHORITY													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
REEDY CREEK - CB													
DUKE ENERGY FLORIDA - MA													
FLORIDA POWER & LIGHT - MA													
CITY OF LAKELAND - MA													
ORLANDO UTILITIES - MA													
EXGEN - MA													
REEDY CREEK - MA													
THE ENERGY AUTHORITY - MA													
MACQUARIE ENERGY LLC - MA													
MORGAN STANLEY - MA													
SOUTHERN CO - MA													
NEW SMYRNA BEACH - MA													
EDF TRADING - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	**$ 583,902**	**$ 872,960**	**$ 668,109**	**$ 639,970**	**$ 1,074,286**	**$ 1,142,022**	**$ 1,183,470**	**$ 1,251,270**	**$ 1,248,984**	**$ 1,204,852**	**$ 855,876**	**$ 746,067**	**$ 11,471,768**
TOTAL CAPACITY	**$ 583,902**	**$ 872,960**	**$ 668,109**	**$ 639,970**	**$ 1,074,286**	**$ 1,142,022**	**$ 1,183,470**	**$ 1,251,270**	**$ 1,248,984**	**$ 1,204,852**	**$ 855,876**	**$ 746,067**	**$ 11,471,768**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 5

CAPITAL PROJECTS APPROVED FOR FUEL CLAUSE RECOVERY

JANUARY 2018 – DECEMBER 2018

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951							$16,143,951
2	ADD INVESTMENT	-	-	-	-	-	-							-
3	LESS RETIREMENTS	-	-	-	-	-	-							-
4	ENDING BALANCE	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951							$16,143,951
5														
6														
7	AVERAGE BALANCE	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951	$16,143,951							
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%							
9	DEPRECIATION EXPENSE	$269,225	$269,225	$269,225	$269,225	$269,225	$269,225							$1,615,350
10	LESS RETIREMENTS	-	-	-	-	-	-							-
11	BEGINNING BALANCE DEPRECIATION	$14,528,600	$14,797,825	$15,067,050	$15,336,276	$15,605,501	$15,874,726							$14,528,600
12	ENDING BALANCE DEPRECIATION	$14,797,825	$15,067,050	$15,336,276	$15,605,501	$15,874,726	$16,143,951							$16,143,951
13														
14														
15	ENDING NET INVESTMENT	$1,346,125	$1,076,900	$807,675	$538,450	$269,225	-							-
16														
17														
18	AVERAGE INVESTMENT	$1,480,738	$1,211,513	$942,288	$673,063	$403,838	$134,613							
19	ALLOWED EQUITY RETURN	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%							
20	EQUITY COMPONENT AFTER-TAX	$5,295	$4,332	$3,370	$2,407	$1,444	$481							$17,329
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.34295	1.34295							
22	EQUITY COMPONENT PRE-TAX	$8,642	$7,071	$5,501	$3,929	$1,939	$646							$27,728
23														
24	ALLOWED DEBT RETURN	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%							
25	DEBT COMPONENT	$2,216	$1,813	$1,410	$1,007	$604	$201							$7,251
26														
27	TOTAL RETURN REQUIREMENTS	$10,858	$8,884	$6,911	$4,936	$2,543	$847							$34,979
28														
29	TOTAL DEPRECIATION & RETURN	$280,083	$278,109	$276,136	$274,161	$271,768	$270,072							$1,650,329
30														
31	ESTIMATED FUEL SAVINGS	$1,717,841	$368,978	$9,068,543	$17,090,426	$18,774,508	$16,192,630							$63,212,927
32	TOTAL DEPRECIATION & RETURN	$280,083	$278,109	$276,136	$274,161	$271,768	$270,072							$1,650,329
33	NET BENEFIT (COST) TO RATEPAYER	$1,437,758	$90,869	$8,792,407	$16,816,265	$18,502,740	$15,922,558							$61,562,598
34	TAX REFORM TRUEUP (EXCLUDING INTEREST)					($4,456)								($4,456)

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.

36 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - JUNE USING AN ANNUAL RATE OF 7.5587% (EQUITY 5.7628% , DEBT 1.7959%). RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - DECEMBER USING AN ANNUAL RATE OF 7.5190% (EQUITY 5.8046% , DEBT 1.7144%) RATES ARE BASED ON THE MAY 2018 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).

37 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - JUNE USING AN ANNUAL RATE OF 7.5587% (EQUITY 5.7628% , DEBT 1.7959%). RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - DECEMBER USING AN ANNUAL RATE OF 7.5190% (EQUITY 5.8046% , DEBT 1.7144%) RATES ARE BASED ON THE MAY 2018 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).

38 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 25.345%

39 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

40 TAX REFORM TRUE-UP AMOUNT, INCLUDING INTEREST, IS SHOWN ON MAY 2018 SCHEDULE A2 AT LINE C.8.b. THE TOTAL TRUE-UP IS ($43,064), WHICH CONSISTS OF ($4,456) + ($38,477) + ($131).

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$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	$20,910,348	$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	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9	DEPRECIATION EXPENSE	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$4,182,070
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	$10,913,710	$11,262,216	$11,610,722	$11,959,228	$12,307,734	$12,656,239	$13,004,745	$13,353,251	$13,701,757	$14,050,263	$14,398,768	$14,747,274	$10,913,710
12	ENDING BALANCE DEPRECIATION	$11,262,216	$11,610,722	$11,959,228	$12,307,734	$12,656,239	$13,004,745	$13,353,251	$13,701,757	$14,050,263	$14,398,768	$14,747,274	$15,095,780	$15,095,780
13														
14														
15	ENDING NET INVESTMENT	$9,648,132	$9,299,626	$8,951,120	$8,602,615	$8,254,109	$7,905,603	$7,557,097	$7,208,591	$6,860,086	$6,511,580	$6,163,074	$5,814,568	$5,814,568
16														
17														
18	AVERAGE INVESTMENT	$9,822,385	$9,473,879	$9,125,373	$8,776,867	$8,428,362	$8,079,856	$7,731,350	$7,382,844	$7,034,338	$6,685,833	$6,337,327	$5,988,821	
19	ALLOWED EQUITY RETURN	.35760%	.35760%	.35760%	.35760%	.35760%	.35760%	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	
20	EQUITY COMPONENT AFTER-TAX	$35,125	$33,878	$32,632	$31,386	$30,140	$28,893	$27,848	$26,592	$25,337	$24,082	$22,827	$21,571	$340,311
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	
22	EQUITY COMPONENT PRE-TAX	$57,331	$55,296	$53,262	$51,228	$40,477	$38,802	$37,398	$35,712	$34,026	$32,341	$30,656	$28,969	$495,498
23														
24	ALLOWED DEBT RETURN	.14966%	.14966%	.14966%	.14966%	.14966%	.14966%	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	
25	DEBT COMPONENT	$14,700	$14,179	$13,657	$13,136	$12,614	$12,092	$11,046	$10,548	$10,050	$9,552	$9,054	$8,556	$139,184
26														
27	TOTAL RETURN REQUIREMENTS	$72,031	$69,475	$66,919	$64,364	$53,091	$50,894	$48,444	$46,260	$44,076	$41,893	$39,710	$37,525	$634,682
28	PRIOR MONTH TRUE-UP													
29	TOTAL DEPRECIATION & RETURN	$420,537	$417,981	$415,425	$412,870	$401,597	$399,400	$396,950	$394,766	$392,582	$390,399	$388,216	$386,031	$4,816,752
30														
31	ESTIMATED FUEL SAVINGS	$368,460	$796,030	$230,045	$437,507	$385,672	$700,247	$334,668	$313,580	$310,913	$488,425	$685,268	$186,674	$5,237,489
32	TOTAL DEPRECIATION & RETURN	$420,537	$417,981	$415,425	$412,870	$401,597	$399,400	$396,950	$394,766	$392,582	$390,399	$388,216	$386,031	$4,816,752
33	NET BENEFIT (COST) TO RATEPAYER	**($52,077)**	**$378,050**	**($185,380)**	**$24,637**	**($15,925)**	**$300,847**	**($62,282)**	**($81,186)**	**($81,669)**	**$98,026**	**$297,052**	**($199,356)**	**$420,738**
34	TAX REFORM TRUEUP (EXCLUDING INTEREST)					($38,477)								($38,477)

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.

36 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - JUNE USING AN ANNUAL RATE OF 7.5587% (EQUITY 5.7628% , DEBT 1.7959%). RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - DECEMBER USING AN ANNUAL RATE OF 7.5190% (EQUITY 5.8046% , DEBT 1.7144%) RATES ARE BASED ON THE MAY 2018 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).

37 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - JUNE USING AN ANNUAL RATE OF 7.5587% (EQUITY 5.7628% , DEBT 1.7959%). RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - DECEMBER USING AN ANNUAL RATE OF 7.5190% (EQUITY 5.8046% , DEBT 1.7144%) RATES ARE BASED ON THE MAY 2018 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).

38 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 25.345%

39 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

40 TAX REFORM TRUE-UP AMOUNT, INCLUDING INTEREST, IS SHOWN ON MAY 2018 SCHEDULE A2 AT LINE C.8.b. THE TOTAL TRUE-UP IS ($43,064), WHICH CONSISTS OF ($4,456) + ($38,477) + ($131).

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
January 2018 to June 2018

	(1) Jurisdictional Rate Base Actual May 2017 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,611,554	33.14%	5.12%	1.6968%
Short Term Debt	118,708	2.44%	1.55%	0.0378%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	101,181	2.08%	2.55%	0.0531%
Common Equity	2,031,177	41.77%	10.25%	4.2815%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	988,845	20.34%	0.00%	0.0000%
Deferred ITC - Weighted Cost	11,216	0.23%	7.78%	0.0179%
Total	$ 4,862,681	100.00%		6.09%

ITC split between Debt and Equity:

Long Term Debt	$ 1,611,554	Long Term Debt	42.84%
Short Term Debt	118,708	Short Term Debt	3.16%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,031,177	Equity - Common	54.00%
Total	$ 3,761,439	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.0179% * 46.00%	0.0082%
Equity = 0.0179% * 54.00%	0.0097%
Weighted Cost	0.0179%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.2815%
Deferred ITC - Weighted Cost	0.0097%
	4.2912%
Times Tax Multiplier	1.34295
Total Equity Component	5.7628%

Total Debt Cost Rate:

Long Term Debt	1.6968%
Short Term Debt	0.0378%
Customer Deposits	0.0531%
Deferred ITC - Weighted Cost	0.0082%
Total Debt Component	1.7959%
	7.5587%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 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 Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
July 2018 to December 2018

	(1) Jurisdictional Rate Base Actual May 2018 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,719,219	30.51%	5.13%	1.5652%
Short Term Debt	244,333	4.34%	2.18%	0.0945%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	96,005	1.70%	2.43%	0.0414%
Common Equity	2,367,502	42.02%	10.25%	4.3067%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,187,473	21.07%	0.00%	0.0000%
Deferred ITC - Weighted Cost	20,116	0.36%	8.10%	0.0289%
Total	$ 5,634,648	100.00%		6.04%

ITC split between Debt and Equity:

Long Term Debt	$ 1,719,219	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,367,502	Equity - Common	54.00%
Total	$ 4,086,721	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.0289% * 46.00%	0.0133%
Equity = 0.0289% * 54.00%	0.0156%
Weighted Cost	0.0289%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3067%
Deferred ITC - Weighted Cost	0.0156%
	4.3223%
Times Tax Multiplier	1.34295
Total Equity Component	5.8046%

Total Debt Cost Rate:

Long Term Debt	1.5652%
Short Term Debt	0.0945%
Customer Deposits	0.0414%
Deferred ITC - Weighted Cost	0.0133%
Total Debt Component	1.7144%
	7.5190%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012 and 2017 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 Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

FUEL AND PURCHASED POWER COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2019 THROUGH DECEMBER 2019

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 62
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-2

TAMPA ELECTRIC COMPANY

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2	Schedule E1-A Calculation of Total True-Up	(JAN. 2020 - DEC. 2020)
3	Schedule E1-B Calculation of Estimated True-Up	(JAN. 2019 - DEC. 2019)
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 2020 THROUGH DECEMBER 2020

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2019 - December 2019 (6 months actual, 6 months estimated)	($27,562,704)
2.	PROJECTED UNDER-RECOVERY TRUE-UP INCLUDED IN APRIL - DECEMBER 2019 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	($35,545,462)
3.	DIFFERENCE IN 2018 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2019 RATES AND AMOUNT COLLECTED IN 2019 ($7,015,485 over-recovery less $584,624 refunded each month January through March 2019)	$5,261,613
4.	ACTUAL-ESTIMATED 2019 OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2020 (Line 1 - Line 2 + Line 3)	$13,244,371
5.	FINAL TRUE-UP (January 2018 - December 2018) (Per True-Up filed March 1, 2019)	(43,986,397)
6.	TOTAL OVER/(UNDER) RECOVERY (Line 4 + Line 5) To be included in the 12-month projected period January 2020 through December 2020 (Schedule E1, line 28)	($30,742,026)
7.	JURISDICTIONAL MWH SALES (Projected January 2020 through December 2020)	19,618,479
8.	TRUE-UP FACTOR - cents/kWh (Line 6 / Line 7 * 100 cents / 1,000 kWh)	**0.1567**

TAMPA ELECTRIC COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

SCHEDULE E1-B

		ACTUAL						ESTIMATED						
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	TOTAL
A. 1.	Fuel Cost of System Net Generation	49,606,343	38,597,469	40,176,296	43,477,069	50,800,286	47,406,580	51,830,901	53,810,457	48,923,283	43,794,168	42,168,783	45,957,217	556,548,852
2.	Fuel Cost of Power Sold (1)	169,947	119,888	111,628	130,003	562,515	437,747	16,118	16,459	17,463	17,582	18,024	18,630	1,636,004
3.	Fuel Cost of Purchased Power	35,101	113,816	7,752	19,463	26,772	11,567	0	0	0	0	0	0	214,471
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	621,159	347,789	265,526	375,556	380,746	282,612	299,280	297,310	317,540	299,630	278,720	308,860	4,074,728
4.	Energy Cost of Economy Purchases	632,705	253,771	1,740,312	2,497,767	1,569,479	7,939,932	6,403,130	6,391,970	6,229,950	6,404,170	441,550	82,660	40,587,396
5.	Adj. Big Bend Units 1-4 Igniters Conversion Project	383,847	381,664	379,479	377,296	375,113	372,930	371,476	369,221	366,965	364,709	362,456	360,199	4,465,355
5a.	Adj. Polk 1 conversion depreciation & ROI	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.**	**51,109,208**	**39,574,621**	**42,457,737**	**46,617,148**	**52,589,881**	**55,575,874**	**58,888,669**	**60,852,499**	**55,820,275**	**50,845,095**	**43,233,485**	**46,690,306**	**604,254,798**
(1)	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,409,524	1,410,848	1,397,135	1,381,922	1,647,400	1,893,748	1,895,777	1,889,610	1,980,493	1,789,875	1,495,445	1,426,702	19,618,479
2.	Non-Jurisdictional MWH Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	**TOTAL SALES (LINE B1+B2)**	**1,409,524**	**1,410,848**	**1,397,135**	**1,381,922**	**1,647,400**	**1,893,748**	**1,895,777**	**1,889,610**	**1,980,493**	**1,789,875**	**1,495,445**	**1,426,702**	**19,618,479**
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)	37,659,589	37,625,753	37,045,249	43,642,623	52,821,605	61,699,104	61,957,972	61,718,738	64,757,180	57,787,745	47,492,569	45,193,784	609,401,911
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	584,624	584,624	584,624	(3,949,496)	(3,949,496)	(3,949,496)	(3,949,496)	(3,949,496)	(3,949,496)	(3,949,496)	(3,949,496)	(3,949,494)	(33,791,590)
2a.	Incentive Provision	188,418	188,418	188,418	188,418	188,418	188,418	188,418	188,418	188,418	188,418	188,418	188,421	2,261,019
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**38,432,631**	**38,398,795**	**37,818,291**	**39,881,545**	**49,060,527**	**57,938,026**	**58,196,894**	**57,957,660**	**60,996,102**	**54,026,667**	**43,731,491**	**41,432,711**	**577,871,340**
4.	Total Fuel and Net Power Transactions (Line A6)	51,109,208	39,574,621	42,457,737	46,617,148	52,589,881	55,575,874	58,888,669	60,852,499	55,820,275	50,845,095	43,233,485	46,690,306	604,254,798
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	51,109,208	39,574,621	42,457,737	46,617,148	52,589,881	55,575,874	58,888,669	60,852,499	55,820,275	50,845,095	43,233,485	46,690,306	604,254,798
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	51,109,208	39,574,621	42,457,737	46,617,148	52,589,881	55,575,874	58,888,669	60,852,499	55,820,275	50,845,095	43,233,485	46,690,306	604,254,798
5c.	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS**	**51,109,208**	**39,574,621**	**42,457,737**	**46,617,148**	**52,589,881**	**55,575,874**	**58,888,669**	**60,852,499**	**55,820,275**	**50,845,095**	**43,233,485**	**46,690,306**	**604,254,798**
7.	Over/(Under) Recovery	(12,676,577)	(1,175,826)	(4,639,446)	(6,735,603)	(3,529,354)	2,362,152	(691,775)	(2,894,839)	5,175,827	3,181,572	498,006	(5,257,595)	(26,383,458)
7a.	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Interest Provision	(87,639)	(102,912)	(111,782)	(120,770)	(121,034)	(111,663)	(110,349)	(115,077)	(98,251)	(75,984)	(64,329)	(59,456)	(1,179,246)
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**(27,562,704)**

TAMPA ELECTRIC COMPANY **SCHEDULE E2**
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
		Actual						Estimated						TOTAL
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	PERIOD
1.	Fuel Cost of System Net Generation	49,606,343	38,597,469	40,176,296	43,477,069	50,800,286	47,406,580	51,830,901	53,810,457	48,923,283	43,794,168	42,168,783	45,957,217	556,548,852
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	169,947	119,888	111,628	130,003	562,515	437,747	16,118	16,459	17,463	17,582	18,024	18,630	1,636,004
4.	Fuel Cost of Purchased Power	35,101	113,816	7,752	19,463	26,772	11,567	0	0	0	0	0	0	214,471
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	621,159	347,789	265,526	375,556	380,746	282,612	299,280	297,310	317,540	299,630	278,720	308,860	4,074,728
7.	Energy Cost of Economy Purchases	632,705	253,771	1,740,312	2,497,767	1,569,479	7,939,932	6,403,130	6,391,970	6,229,950	6,404,170	441,550	82,660	40,587,396
8.	Adj. Big Bend Units 1-4 Igniters Conversion Project	383,847	381,664	379,479	377,296	375,113	372,930	371,476	369,221	366,965	364,709	362,456	360,199	4,465,355
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**	**51,109,208**	**39,574,621**	**42,457,737**	**46,617,148**	**52,589,881**	**55,575,874**	**58,888,669**	**60,852,499**	**55,820,275**	**50,845,095**	**43,233,485**	**46,690,306**	**604,254,798**
12.	Jurisdictional MWH Sold	1,409,524	1,410,848	1,397,135	1,381,922	1,647,400	1,893,748	1,895,777	1,889,610	1,980,493	1,789,875	1,495,445	1,426,702	19,618,479
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)	51,109,208	39,574,621	42,457,737	46,617,148	52,589,881	55,575,874	58,888,669	60,852,499	55,820,275	50,845,095	43,233,485	46,690,306	604,254,798
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)	51,109,208	39,574,621	42,457,737	46,617,148	52,589,881	55,575,874	58,888,669	60,852,499	55,820,275	50,845,095	43,233,485	46,690,306	604,254,798
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)**	**51,109,208**	**39,574,621**	**42,457,737**	**46,617,148**	**52,589,881**	**55,575,874**	**58,888,669**	**60,852,499**	**55,820,275**	**50,845,095**	**43,233,485**	**46,690,306**	**604,254,798**
19.	Cost Per kWh Sold (Cents/kWh)	3.6260	2.8050	3.0389	3.3734	3.1923	2.9347	3.1063	3.2204	2.8185	2.8407	2.8910	3.2726	3.0800
20.	Adjustment	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
21.	True-up (Cents/kWh) [2]	(0.0415)	(0.0414)	(0.0418)	0.2858	0.2397	0.2086	0.2083	0.2090	0.1994	0.2207	0.2641	0.2768	0.1656
22.	Total (Cents/kWh) (Line 19+20)	3.5845	2.7636	2.9971	3.6592	3.4320	3.1433	3.3146	3.4294	3.0179	3.0614	3.1551	3.5494	3.2457
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)	3.5871	2.7656	2.9993	3.6618	3.4345	3.1456	3.3170	3.4318	3.0201	3.0636	3.1574	3.5520	3.2480
25.	GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0134)	(0.0134)	(0.0135)	(0.0136)	(0.0114)	(0.0099)	(0.0099)	(0.0100)	(0.0095)	(0.0105)	(0.0126)	(0.0132)	(0.0117)
26.	**TOTAL RECOVERY FACTOR (LINE 23+24)**	**3.5737**	**2.7522**	**2.9858**	**3.6482**	**3.4231**	**3.1357**	**3.3071**	**3.4218**	**3.0106**	**3.0531**	**3.1448**	**3.5388**	**3.2363**
27.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.574**	**2.752**	**2.986**	**3.648**	**3.423**	**3.136**	**3.307**	**3.422**	**3.011**	**3.053**	**3.145**	**3.539**	**3.236**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD: JANUARY 2019 THROUGH JUNE 2019

SCHEDULE E3

	ACTUAL					
	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	0	0	0	0	17,030	12,035
3. COAL	7,027,027	3,185,512	764,747	3,059,647	5,057,428	5,276,546
4. NATURAL GAS	42,579,316	35,411,957	39,411,549	40,417,422	45,725,828	42,117,999
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**49,606,343**	**38,597,469**	**40,176,296**	**43,477,069**	**50,800,286**	**47,406,580**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	0	0	0	0	67	0
10. COAL	211,679	91,159	(2,475)	75,504	133,016	150,660
11. NATURAL GAS	1,218,682	1,199,187	1,355,548	1,373,770	1,718,336	1,577,414
12. SOLAR	33,413	44,520	74,096	80,688	78,453	65,742
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,463,774**	**1,334,866**	**1,427,169**	**1,529,962**	**1,929,872**	**1,793,816**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	0	0	0	0	133	95
17. COAL (TON)	97,492	41,500	(683)	36,085	65,724	68,443
18. NATURAL GAS (MCF)	9,320,260	9,434,950	10,695,636	11,545,290	13,438,626	11,971,401
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	0	0	0	0	779	550
23. COAL	2,279,775	979,271	(16,038)	847,090	1,518,292	1,575,025
24. NATURAL GAS	9,515,986	9,623,650	10,898,853	11,776,196	13,720,837	12,258,736
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**11,795,761**	**10,602,921**	**10,882,815**	**12,623,286**	**15,239,908**	**13,834,311**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.00	0.00	0.00	0.00	0.00	0.00
30. COAL	14.46	6.82	(0.17)	4.94	6.89	8.40
31. NATURAL GAS	83.26	89.84	94.98	89.79	89.04	87.94
32. SOLAR	2.28	3.34	5.19	5.27	4.07	3.66
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)	0.00	0.00	0.00	0.00	128.05	126.68
37. COAL ($/TON)	72.08	76.76	(1,119.69)	84.79	76.95	77.09
38. NATURAL GAS ($/MCF)	4.57	3.75	3.68	3.50	3.40	3.52
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 ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	0.00	0.00	0.00	0.00	21.86	21.88
43. COAL	3.08	3.25	(47.68)	3.61	3.33	3.35
44. NATURAL GAS	4.47	3.68	3.62	3.43	3.33	3.44
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.21**	**3.64**	**3.69**	**3.44**	**3.33**	**3.43**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	0	0	0	0	11,627	0
50. COAL	10,770	10,742	6,480	11,219	11,414	10,454
51. NATURAL GAS	7,808	8,025	8,040	8,572	7,985	7,771
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**8,058**	**7,943**	**7,625**	**8,251**	**7,897**	**7,712**
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	0.00	0.00	0.00	0.00	25.42	0.00
57. COAL	3.32	3.49	(30.90)	4.05	3.80	3.50
58. NATURAL GAS	3.49	2.95	2.91	2.94	2.66	2.67
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)	**3.39**	**2.89**	**2.82**	**2.84**	**2.63**	**2.64**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2019 THROUGH DECEMBER 2019

SCHEDULE E3
REVISED 9/3/19

	Estimated						
	Jul-19	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**TOTAL**
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	0	0	0	0	0	0	0
2. LIGHT OIL	317,757	317,757	307,507	302,382	251,131	317,757	1,843,356
3. COAL	4,658,228	4,693,519	2,238,624	674,636	4,678,032	4,760,784	46,074,730
4. NATURAL GAS	46,854,916	48,799,181	46,377,152	42,817,150	37,239,620	40,878,676	508,630,766
5. SOLAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**51,830,901**	**53,810,457**	**48,923,283**	**43,794,168**	**42,168,783**	**45,957,217**	**556,548,852**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	0	0	0	0	0	0	0
9. LIGHT OIL	1,328	1,328	1,286	1,264	1,050	1,328	7,651
10. COAL	108,360	110,260	53,950	16,380	111,700	112,670	1,172,863
11. NATURAL GAS	1,657,841	1,681,471	1,640,824	1,488,976	1,249,870	1,358,781	17,520,700
12. SOLAR	70,760	73,370	68,200	74,050	59,240	52,690	775,222
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,838,289**	**1,866,429**	**1,764,260**	**1,580,670**	**1,421,860**	**1,525,469**	**19,476,436**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	0	0	0	0	0	0	0
16. LIGHT OIL (BBL)	2,492	2,492	2,412	2,372	1,970	2,492	14,458
17. COAL (TON)	61,590	62,320	30,360	8,840	62,170	62,620	596,461
18. NATURAL GAS (MCF)	12,011,552	12,437,362	11,909,232	10,769,902	9,332,892	9,947,872	132,814,975
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	14,614	14,614	14,143	13,907	11,550	14,614	84,772
23. COAL	1,385,820	1,402,120	683,040	198,940	1,398,770	1,408,920	13,661,025
24. NATURAL GAS	12,329,876	12,737,616	12,223,417	11,043,123	9,568,030	10,205,446	135,901,765
25. SOLAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**13,730,310**	**14,154,350**	**12,920,600**	**11,255,970**	**10,978,350**	**11,628,980**	**149,647,562**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.07	0.07	0.07	0.08	0.07	0.09	0.04
30. COAL	5.90	5.91	3.06	1.04	7.86	7.39	6.02
31. NATURAL GAS	90.18	90.09	93.00	94.20	87.90	89.07	89.96
32. SOLAR	3.85	3.93	3.87	4.68	4.17	3.45	3.98
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)	127.51	127.51	127.49	127.48	127.48	127.51	127.50
37. COAL ($/TON)	75.63	75.31	73.74	76.32	75.25	76.03	77.25
38. NATURAL GAS ($/MCF)	3.90	3.92	3.89	3.98	3.99	4.11	3.83
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 ($/MMBTU)							
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	21.74	21.74	21.74	21.74	21.74	21.74	21.74
43. COAL	3.36	3.35	3.28	3.39	3.34	3.38	3.37
44. NATURAL GAS	3.80	3.83	3.79	3.88	3.89	4.01	3.74
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.77**	**3.80**	**3.79**	**3.89**	**3.84**	**3.95**	**3.72**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	0	0	0	0	0	0	0
49. LIGHT OIL	11,005	11,005	10,998	11,002	11,000	11,005	11,080
50. COAL	12,789	12,716	12,661	12,145	12,523	12,505	11,648
51. NATURAL GAS	7,437	7,575	7,450	7,417	7,655	7,511	7,757
52. SOLAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**7,469**	**7,584**	**7,324**	**7,121**	**7,721**	**7,623**	**7,684**
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	23.93	23.93	23.91	23.92	23.92	23.93	24.09
57. COAL	4.30	4.26	4.15	4.12	4.19	4.23	3.93
58. NATURAL GAS	2.83	2.90	2.83	2.88	2.98	3.01	2.90
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)	**2.82**	**2.88**	**2.77**	**2.77**	**2.97**	**3.01**	**2.86**

SCHEDULE A4
PAGE 1 OF 2
REVISED 6/20/19

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2019

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR		1.6	224	18.8	-	42.9	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR		19.4	2,664	18.5	-	45.0	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR		1.5	135	12.1	-	29.3	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR		70.3	8,052	15.4	-	39.4	-	SOLAR	-	-	-	-	-	-
BALM SOLAR		74.4	10,172	18.4	-	44.8	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR		74.5	9,958	18.0	-	43.8	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR		61.1	1,725	3.9	-	9.3	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	(3)	55.4	(27)	-	-	0.0	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR		37.5	510	6.3	-	13.6	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL		**395.7**	**33,413**	**14.4**	-	**23.0**	-	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
BIG BEND #1 TOTAL		**315**	**15,607**	**6.7**	**81.1**	**37.1**	**13,101**	**GAS**	**200,261**	**1,021,000**	**204,466.1**	**914,771**	**5.86**	**4.57**
BIG BEND #2 TOTAL		**350**	**28,504**	**10.9**	**90.6**	**42.5**	**11,949**	**GAS**	**333,575**	**1,021,000**	**340,580.5**	**1,523,744**	**5.35**	**4.57**
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	94,022	35.6	92.7	64.3	-	GAS	1,076,345	1,021,000	1,098,948.1	4,916,643	5.23	4.57
BIG BEND #3 TOTAL		**355**	**94,022**	**35.6**	**92.7**	**64.3**	**11,688**	**-**	**-**	**-**	**1,098,948.1**	**4,916,643**	**5.23**	**-**
B.B.#4 (COAL)		442	214,551	65.2	72.5	81.3	-	COAL	97,492	23,384,223	2,279,774.7	6,908,042	3.22	70.86
B.B.#4 (GAS)		195	7,723	5.3	48.3	88.0	-	GAS	81,425	1,021,000	83,134.6	371,942	4.82	4.57
BIG BEND #4 TOTAL		**442**	**222,274**	**67.6**	**72.5**	**73.8**	**10,631**	**-**	**-**	**-**	**2,362,909.3**	**7,279,984**	**3.28**	**-**
B.B. IGNITION		-	-	-	-	-	-	GAS	26,048	0	26,595.5	118,985	-	4.57
BIG BEND CT #4 TOTAL		**61**	**227**	**0.5**	**94.7**	**63.4**	**17,640**	**GAS**	**3,922**	**1,021,000**	**4,004.3**	**17,914**	**7.89**	**4.57**
BIG BEND STATION TOTAL		**1,523**	**360,634**	**31.8**	**84.0**	**36.9**	**11,122**	**-**	**-**	**-**	**4,010,908.3**	**14,772,041**	**4.10**	**-**
POLK #1 GASIFIER	(3)	157	(2,872)	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
POLK #1 CT (GAS)		177	19,197	14.6	60.2	56.3	12,865	GAS	241,904	1,021,000	246,984.0	1,104,995	4.12	4.57
POLK #1 ST		85	7,643	12.1	60.2	50.8	0							
POLK #1 TOTAL		**245**	**23,968**	**13.1**	**60.2**	**50.8**	**10,305**	**-**	**-**	**-**	**246,984.0**	**1,104,995**	**4.61**	**-**
POLK #2 ST DUCT FIRING		120	12,531	14.0	-	86.6	8,415	GAS	103,280	1,021,000	105,449.0	471,774	3.76	4.57
POLK #2 ST W/O DUCT FIRING		360	244,806	91.4	-	-	-		-	-	-	-	-	-
POLK #2 ST TOTAL		**480**	**257,337**	**72.1**	**99.8**	**72.2**	**-**	**GAS**	**-**	**-**	**105,449.0**	**471,774**	**0.18**	**-**
POLK #2 CT (GAS)		180	103,735	77.5	99.7	81.4	11,000	GAS	1,117,627	1,021,000	1,141,097.0	5,105,216	4.92	4.57
POLK #2 CT (OIL)		187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL		**180**	**103,735**	**77.5**	**99.7**	**81.4**	**11,000**	**-**	**-**	**-**	**1,141,097.0**	**5,105,216**	**4.92**	**-**
POLK #3 CT (GAS)		180	106,883	79.8	99.8	82.9	10,843	GAS	1,135,125	1,021,000	1,158,963.0	5,185,148	4.85	4.57
POLK #3 CT (OIL)		187	0	0.00	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL		**180**	**106,883**	**79.8**	**99.8**	**82.9**	**10,843**	**-**	**-**	**-**	**1,158,963.0**	**5,185,148**	**4.85**	**-**
POLK #4 TOTAL		**180**	**108,884**	**81.3**	**100.0**	**82.9**	**10,713**	GAS	**1,142,473**	**1,021,000**	**1,166,465.0**	**5,218,711**	**4.79**	**4.57**
POLK #5 TOTAL		**180**	**105,400**	**78.7**	**95.5**	**83.2**	**10,739**	GAS	**1,108,599**	**1,021,000**	**1,131,880.0**	**5,063,980**	**4.80**	**4.57**
POLK #2 CC TOTAL		**1,200**	**682,239**	**76.4**	**98.7**	**76.6**	**6,895**	GAS	**-**	**-**	**4,703,854.0**	**21,044,829**	**3.08**	**-**
POLK STATION TOTAL		**1,445**	**706,207**	**65.7**	**92.1**	**65.8**	**7,010**	**-**	**-**	**-**	**4,950,838.0**	**22,149,824**	**3.14**	**-**

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2019

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1	243	101,589	56.2	100.0	56.2	-		-	-	-	-	-	-
BAYSIDE CT1A	183	57,706	42.4	99.8	64.2	12,122	GAS	685,101	1,021,000	699,487.7	3,130,768	5.43	4.57
BAYSIDE CT1B	183	60,991	44.8	100.0	65.4	12,038	GAS	719,124	1,021,000	734,225.9	3,286,246	5.39	4.57
BAYSIDE CT1C	183	60,820	44.7	100.0	64.5	11,837	GAS	705,129	1,021,000	719,936.9	3,222,293	5.30	4.57
BAYSIDE UNIT 1 TOTAL	**792**	**281,106**	**47.7**	**99.9**	**47.7**	**7,661**	**GAS**	**2,109,354**	**1,021,000**	**2,153,650.6**	**9,639,307**	**3.43**	**4.57**
BAYSIDE ST 2	315	27,013	11.5	35.7	35.5	-		-	-	-	-	-	-
BAYSIDE CT2A	183	9,001	6.6	43.6	65.7	12,057	GAS	106,293	1,021,000	108,525.4	485,737	5.40	4.57
BAYSIDE CT2B	183	7,087	5.2	43.7	65.6	12,391	GAS	86,009	1,021,000	87,815.5	393,043	5.55	4.57
BAYSIDE CT2C	183	13,638	10.0	36.4	62.7	12,425	GAS	165,965	1,021,000	169,449.8	758,425	5.56	4.57
BAYSIDE CT2D	183	23,969	17.6	42.3	62.0	12,328	GAS	289,418	1,021,000	295,495.8	1,322,580	5.52	4.57
BAYSIDE UNIT 2 TOTAL	**1,047**	**80,708**	**10.4**	**33.7**	**31.9**	**8,194**	**GAS**	**647,685**	**1,021,000**	**661,286.5**	**2,959,785**	**3.67**	**4.57**
BAYSIDE UNIT 3 TOTAL	**61**	**73**	**0.2**	**100.0**	**66.1**	**15,021**	**GAS**	**1,074**	**1,021,000**	**1,096.5**	**4,908**	**6.72**	**4.57**
BAYSIDE UNIT 4 TOTAL	**61**	**367**	**0.8**	**100.0**	**90.5**	**10,674**	**GAS**	**3,837**	**1,021,000**	**3,917.4**	**17,533**	**4.78**	**4.57**
BAYSIDE UNIT 5 TOTAL	**61**	**537**	**1.2**	**100.0**	**83.6**	**11,900**	**GAS**	**6,259**	**1,021,000**	**6,390.3**	**28,602**	**5.33**	**4.57**
BAYSIDE UNIT 6 TOTAL	**61**	**729**	**1.6**	**100.0**	**89.9**	**10,525**	**GAS**	**7,515**	**1,021,000**	**7,673.0**	**34,343**	**4.71**	**4.57**
BAYSIDE STATION TOTAL	**2,083**	**363,520**	**23.5**	**66.6**	**23.5**	**7,796**	**GAS**	**2,775,724**	**1,021,000**	**2,834,014.4**	**12,684,478**	**3.49**	**4.57**
SYSTEM	**5,447**	**1,463,774**	**36.7**	**79.2**	**39.1**	**8,058**	**-**	**-**	**-**	**11,795,760.6**	**49,606,343**	**3.39**	**-**

LEGEND:

B.B. = BIG BEND **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM TURBINE**

Footnotes:

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] Station Service

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2019

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR	1.6	220	20.5	-	36.8	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.4	2,664	20.4	-	45.9	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	131	13.0	-	28.9	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.3	8,999	19.0	-	43.5	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.4	8,417	16.8	-	38.5	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.5	11,289	22.5	-	50.8	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	61.1	7,613	18.5	-	40.7	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	55.4	833	-	-	11.6	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.5	4,354	17.3	-	37.8	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	**395.7**	**44,520**	**19.5**	-	**26.8**	-	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
BIG BEND #1 TOTAL	**315**	**0**	**0.0**	**35.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BIG BEND #2 TOTAL	**350**	**69,440**	**29.5**	**53.3**	**50.5**	**12,081**	**GAS**	**822,440**	**1,020,000**	**838,888.9**	**3,086,449**	**4.44**	**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	164,819	69.1	95.0	71.4	-	GAS	1,714,122	1,020,000	1,748,404.6	6,432,750	3.90	3.75
BIG BEND #3 TOTAL	**355**	**164,819**	**69.1**	**95.0**	**71.4**	**10,608**	**-**	**-**	**-**	**1,748,404.6**	**6,432,750**	**3.90**	**-**
B.B.#4 (COAL)	442	93,724	31.6	82.3	86.2	-	COAL	41,500	23,598,830	979,271.4	3,252,540	3.47	78.37
B.B.#4 (GAS)	195	5,332	4.1	99.9	68.4	-	GAS	54,443	1,020,000	55,531.6	204,314	3.83	3.75
BIG BEND #4 TOTAL	**442**	**99,056**	**33.3**	**82.3**	**78.4**	**10,285**	**-**	**-**	**-**	**1,034,803.0**	**3,456,854**	**3.49**	**-**
B.B. IGNITION	-	-	-	-	-	-	GAS	23,271	0	23,736.4	87,333	-	3.75
BIG BEND CT #4 TOTAL	**61**	**224**	**0.5**	**100.0**	**45.9**	**15,463**	**GAS**	**3,396**	**1,020,000**	**3,463.8**	**12,745**	**5.69**	**3.75**
BIG BEND STATION TOTAL	**1,523**	**333,539**	**32.6**	**69.5**	**32.6**	**10,822**	**-**	**-**	**-**	**3,625,560.3**	**13,076,131**	**3.92**	**-**
POLK #1 GASIFIER [3]	157	(2,565)	0.0	19.7	0.0	0	COAL	0	0	0.0	(154,361)	6.02	0.00
POLK #1 CT (GAS)	177	4,984	4.2	18.0	52.8	12,547	GAS	61,309	1,020,000	62,535.0	230,079	3.35	3.75
POLK #1 ST	85	1,876	3.3	18.0	32.9	0		-	-	-	-	-	-
POLK #1 TOTAL	**245**	**4,295**	**2.6**	**18.0**	**32.9**	**14,559**	**-**	**-**	**-**	**62,535.0**	**75,718**	**1.76**	**-**
POLK #2 ST DUCT FIRING	120	3,135	3.9	-	59.3	9,852	GAS	30,284	1,020,000	30,890.0	113,651	3.63	3.75
POLK #2 ST W/O DUCT FIRING	360	134,215	55.5	-	-	-		-	-	-	-	-	-
POLK #2 ST TOTAL	**480**	**137,350**	**42.6**	**95.4**	**44.5**	**-**	**GAS**	**-**	**-**	**30,890.0**	**113,651**	**0.08**	**-**
POLK #2 CT (GAS)	180	53,346	44.1	99.9	75.4	11,163	GAS	583,833	1,020,000	595,510.0	2,191,006	4.11	3.75
POLK #2 CT (OIL)	187	0	0.0	99.9	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**180**	**53,346**	**44.1**	**99.9**	**75.4**	**11,163**	**-**	**-**	**-**	**595,510.0**	**2,191,006**	**4.11**	**-**
POLK #3 CT (GAS)	180	67,003	55.4	99.4	78.4	10,957	GAS	719,761	1,020,000	734,156.0	2,701,114	4.03	3.75
POLK #3 CT (OIL)	187	0	0.00	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**180**	**67,003**	**55.4**	**99.4**	**78.4**	**10,957**	**-**	**-**	**-**	**734,156.0**	**2,701,114**	**4.03**	**-**
POLK #4 TOTAL	**180**	**48,721**	**40.3**	**99.5**	**78.1**	**10,840**	**GAS**	**517,770**	**1,020,000**	**528,125.0**	**1,943,083**	**3.99**	**3.75**
POLK #5 TOTAL	**180**	**71,478**	**59.1**	**100.0**	**78.5**	**10,860**	**GAS**	**761,062**	**1,020,000**	**776,283.0**	**2,856,108**	**4.00**	**3.75**
POLK #2 CC TOTAL	**1,200**	**377,898**	**46.9**	**95.3**	**49.0**	**7,052**	**GAS**	**-**	**-**	**2,664,964.0**	**9,804,962**	**2.59**	**-**
POLK STATION TOTAL	**1,445**	**382,193**	**39.4**	**82.2**	**41.1**	**7,136**	**-**	**-**	**-**	**2,727,499.0**	**9,880,680**	**2.59**	**-**

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2019

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1		243	94,226	57.7	85.4	65.0	-		-	-	-	-	-	-
BAYSIDE CT1A		183	58,237	47.4	81.6	70.6	11,491	GAS	656,078	1,020,000	669,199.0	2,462,837	4.23	3.75
BAYSIDE CT1B		183	53,110	43.2	85.4	72.7	11,378	GAS	592,448	1,020,000	604,296.9	2,223,978	4.19	3.75
BAYSIDE CT1C		183	62,790	51.1	88.9	71.2	11,183	GAS	688,407	1,020,000	702,175.1	2,584,198	4.12	3.75
BAYSIDE UNIT 1 TOTAL		**792**	**268,363**	**50.4**	**87.8**	**56.8**	**7,362**	**GAS**	**1,936,933**	**1,020,000**	**1,975,671.1**	**7,271,013**	**2.71**	**3.75**
BAYSIDE ST 2		315	105,336	49.8	63.3	56.3	-		-	-	-	-	-	-
BAYSIDE CT2A		183	46,703	38.0	58.9	73.5	11,061	GAS	506,444	1,020,000	516,573.4	1,901,131	4.07	3.75
BAYSIDE CT2B		183	57,290	46.6	74.3	72.3	11,348	GAS	637,356	1,020,000	650,103.5	2,392,559	4.18	3.75
BAYSIDE CT2C		183	45,446	37.0	66.7	70.4	11,459	GAS	510,566	1,020,000	520,777.8	1,916,604	4.22	3.75
BAYSIDE CT2D		183	50,770	41.3	67.8	70.6	11,388	GAS	566,819	1,020,000	578,155.1	2,127,771	4.19	3.75
BAYSIDE UNIT 2 TOTAL		**1,047**	**305,545**	**43.4**	**80.8**	**49.1**	**7,415**	**GAS**	**2,221,185**	**1,020,000**	**2,265,609.7**	**8,338,065**	**2.73**	**3.75**
BAYSIDE UNIT 3 TOTAL	(3)	**61**	**(26)**	**0.0**	**97.6**	**0.0**	**0**	**GAS**	**0**	**1,020,000**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE UNIT 4 TOTAL	(3)	**61**	**(11)**	**0.0**	**97.6**	**0.0**	**0**	**GAS**	**0**	**1,020,000**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE UNIT 5 TOTAL		**61**	**651**	**1.6**	**96.1**	**82.1**	**11,455**	**GAS**	**7,311**	**1,020,000**	**7,457.5**	**27,446**	**4.22**	**3.75**
BAYSIDE UNIT 6 TOTAL		**61**	**92**	**0.2**	**96.2**	**75.4**	**12,209**	**GAS**	**1,101**	**1,020,000**	**1,123.2**	**4,134**	**4.49**	**3.75**
BAYSIDE STATION TOTAL		**2,083**	**574,614**	**41.1**	**85.3**	**41.1**	**7,396**	**GAS**	**4,166,530**	**1,020,000**	**4,249,861.5**	**15,640,658**	**2.72**	**3.75**
SYSTEM		**5,447**	**1,334,866**	**36.8**	**79.7**	**40.1**	**7,931**	**-**	**-**	**-**	**10,602,920.8**	**38,597,469**	**2.89**	**-**

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] Station Service

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2019

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR		1.6	302	25.4	-	53.6	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR		19.4	3,804	26.4	-	56.3	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR		1.5	186	16.7	-	35.0	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR		70.3	12,806	24.5	-	52.6	-	SOLAR	-	-	-	-	-	-
BALM SOLAR		74.4	12,836	23.2	-	49.9	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR		74.5	16,044	28.9	-	61.7	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR		61.1	10,873	23.9	-	50.8	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR		55.4	9,886	24.0	-	51.2	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR		37.5	7,359	26.4	-	55.3	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL		**395.7**	**74,096**	**25.2**	-	**46.9**	-	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
BIG BEND #1 TOTAL		**315**	**95,509**	**40.8**	**66.5**	**61.1**	**12,669**	**GAS**	**1,187,469**	**1,019,000**	**1,210,030.5**	**4,375,127**	**4.58**	**3.68**
BIG BEND #2 TOTAL		**350**	**22,089**	**8.5**	**68.0**	**49.4**	**13,471**	**GAS**	**292,010**	**1,019,000**	**297,558.1**	**1,075,885**	**4.87**	**3.68**
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	73,668	27.9	78.6	66.1	-	GAS	773,392	1,019,000	788,086.7	2,849,498	3.87	3.68
BIG BEND #3 TOTAL		**355**	**73,668**	**27.9**	**78.6**	**66.1**	**10,698**	**-**	**-**	**-**	**788,086.7**	**2,849,498**	**3.87**	**-**
B.B.#4 (COAL)	(4)	442	0	0.0	80.3	0.0	-	COAL	(683)	0	(16,038.0)	696,128	0.00	(1,019.22)
B.B.#4 (GAS)		195	0	0.0	80.3	0.0	-	GAS	0	1,019,000	0.0	0	0.00	0.00
BIG BEND #4 TOTAL		**442**	**0**	**0.0**	**80.3**	**0.0**	**0**	**-**	**-**	**-**	**(16,038.0)**	**696,128**	**0.00**	**-**
B.B. IGNITION		-	-	-	-	-	-	GAS	18,624	0	18,978.0	68,619	-	3.68
BIG BEND CT #4 TOTAL		**61**	**128**	**0.3**	**79.3**	**49.4**	**21,896**	**GAS**	**2,750**	**1,019,000**	**2,802.7**	**10,135**	**7.92**	**3.69**
BIG BEND STATION TOTAL		**1,523**	**191,394**	**16.9**	**74.2**	**25.3**	**12,009**	**-**	**-**	**-**	**2,282,440.1**	**9,075,392**	**4.74**	**-**
POLK #1 GASIFIER	(3)	157	(2,475)	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
POLK #1 CT (GAS)		177	45,114	36.5	81.8	59.3	12,235	GAS	541,667	1,019,000	551,959.0	1,995,726	3.14	3.68
POLK #1 ST		85	18,473	29.2	82.0	48.1	0		-	-	-	-	-	-
POLK #1 TOTAL		**245**	**61,112**	**33.9**	**81.8**	**55.1**	**9,032**	**-**	**-**	**-**	**551,959.0**	**1,995,726**	**3.27**	**-**
POLK #2 ST DUCT FIRING		120	8,377	9.4	-	85.6	8,400	GAS	69,056	1,019,000	70,368.0	254,431	3.04	3.68
POLK #2 ST W/O DUCT FIRING		360	188,172	70.4	-	-	-		-	-	-	-	-	-
POLK #2 ST TOTAL		**480**	**196,549**	**55.0**	**99.6**	**85.6**	**-**	**GAS**	**-**	**-**	**70,368.0**	**254,431**	**0.13**	**-**
POLK #2 CT (GAS)		180	78,280	58.5	98.1	82.4	11,192	GAS	859,777	1,019,000	876,113.0	3,167,775	4.05	3.68
POLK #2 CT (OIL)		187	0	0.0	98.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL		**180**	**78,280**	**58.5**	**98.1**	**82.4**	**11,192**	**-**	**-**	**-**	**876,113.0**	**3,167,775**	**4.05**	**-**
POLK #3 CT (GAS)		180	81,277	60.7	100.0	79.1	11,014	GAS	878,463	1,019,000	895,154.0	3,236,622	3.98	3.68
POLK #3 CT (OIL)		187	0	0.00	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL		**180**	**81,277**	**60.7**	**100.0**	**79.1**	**11,014**	**-**	**-**	**-**	**895,154.0**	**3,236,622**	**3.98**	**-**
POLK #4 TOTAL		**180**	**87,742**	**65.5**	**100.0**	**80.3**	**10,826**	GAS	**932,155**	**1,019,000**	**949,866.0**	**3,434,445**	**3.91**	**3.68**
POLK #5 TOTAL		**180**	**83,840**	**62.6**	**100.0**	**79.6**	**10,886**	GAS	**895,687**	**1,019,000**	**912,705.0**	**3,300,081**	**3.94**	**3.68**
POLK #2 CC TOTAL		**1,200**	**527,688**	**59.1**	**99.5**	**59.1**	**7,020**	GAS	**-**	**-**	**3,704,206.0**	**13,393,354**	**2.54**	**-**
POLK STATION TOTAL		**1,445**	**588,800**	**54.9**	**96.6**	**54.9**	**7,229**	**-**	**-**	**-**	**4,256,165.0**	**15,389,080**	**2.61**	**-**

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2019

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1		243	0	0.0	0.0	0.0	-		-	-	-	-	-	-
BAYSIDE CT1A	(3)	183	(163)	0.0	0.0	0.0	0	GAS	0	1,019,000	0.0	0	0.00	0.00
BAYSIDE CT1B	(3)	183	(163)	0.0	0.0	0.0	0	GAS	0	1,019,000	0.0	0	0.00	0.00
BAYSIDE CT1C	(3)	183	(163)	0.0	0.0	0.0	0	GAS	0	1,019,000	0.0	0	0.00	0.00
BAYSIDE UNIT 1 TOTAL		**792**	**(489)**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE ST 2		315	198,694	84.8	98.5	86.0	-		-	-	-	-	-	-
BAYSIDE CT2A		183	91,726	67.5	99.9	71.6	11,388	GAS	1,025,131	1,019,000	1,044,608.4	3,778,065	4.12	3.69
BAYSIDE CT2B		183	91,663	67.4	100.0	71.1	11,665	GAS	1,049,351	1,019,000	1,069,288.4	3,867,326	4.22	3.69
BAYSIDE CT2C		183	93,745	67.3	100.0	69.7	11,676	GAS	1,074,189	1,019,000	1,094,599.0	3,958,865	4.22	3.69
BAYSIDE CT2D		183	96,346	70.8	100.0	70.8	11,642	GAS	1,100,738	1,019,000	1,121,652.5	4,056,710	4.21	3.69
BAYSIDE UNIT 2 TOTAL		**1,047**	**572,174**	**86.9**	**99.5**	**86.9**	**7,568**	**GAS**	**4,249,409**	**1,019,000**	**4,330,148.3**	**15,660,966**	**2.74**	**3.69**
BAYSIDE UNIT 3 TOTAL		**61**	**168**	**0.4**	**90.5**	**63.8**	**12,604**	**GAS**	**2,078**	**1,019,000**	**2,117.4**	**7,658**	**4.56**	**3.69**
BAYSIDE UNIT 4 TOTAL		**61**	**224**	**0.5**	**99.6**	**72.6**	**11,112**	**GAS**	**2,443**	**1,019,000**	**2,489.0**	**9,002**	**4.02**	**3.68**
BAYSIDE UNIT 5 TOTAL		**61**	**481**	**1.1**	**99.6**	**74.0**	**12,030**	**GAS**	**5,679**	**1,019,000**	**5,786.2**	**20,927**	**4.35**	**3.68**
BAYSIDE UNIT 6 TOTAL		**61**	**321**	**0.7**	**99.6**	**66.8**	**11,431**	**GAS**	**3,601**	**1,019,000**	**3,669.2**	**13,271**	**4.13**	**3.69**
BAYSIDE STATION TOTAL		**2,083**	**572,879**	**43.8**	**70.2**	**43.8**	**7,583**	**GAS**	**4,263,210**	**1,019,000**	**4,344,210.2**	**15,711,824**	**2.74**	**3.69**
SYSTEM		**5,447**	**1,427,169**	**35.2**	**78.9**	**40.3**	**7,637**	**-**	**-**	**-**	**10,882,815.2**	**40,176,296**	**2.82**	**-**

LEGEND:
B.B. = BIG BEND **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM TURBINE**

Footnotes:
[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] Station Service
[4] Includes adjustment of (683) tons consumed, $171,336.31 of fuel expense and (16,038.0) mmbtu's for February 2019.

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2019

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR	1.6	322	28.0	-	53.1	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.4	4,256	30.5	-	65.6	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	214	19.8	-	42.3	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.3	14,130	27.9	-	60.5	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.4	15,276	28.5	-	62.4	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.5	12,797	23.9	-	51.7	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	61.1	11,423	26.0	-	56.9	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	55.4	12,122	30.4	-	67.0	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.5	8,345	30.9	-	64.9	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK	49.5	1,803	25.3	-	59.6	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	**445.2**	**80,688**	**27.6**	-	**47.9**	-	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
BIG BEND #1 TOTAL	**305**	**108,049**	**49.2**	**99.9**	**49.2**	**13,935**	**GAS**	**1,373,398**	**1,020,000**	**1,400,866.3**	**4,806,994**	**4.45**	**3.50**
BIG BEND #2 TOTAL	**340**	**63,277**	**25.8**	**52.2**	**40.4**	**13,824**	**GAS**	**796,839**	**1,020,000**	**812,775.5**	**2,788,996**	**4.41**	**3.50**
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	94,094	37.9	69.1	60.1	-	GAS	1,216,528	1,020,000	1,240,859.0	4,257,939	4.53	3.50
BIG BEND #3 TOTAL	**345**	**94,094**	**37.9**	**69.1**	**60.1**	**11,285**	**-**	**-**	**-**	**1,240,859.0**	**4,257,939**	**4.53**	**-**
B.B.#4 (COAL)	437	77,428	24.6	34.7	96.8	-	COAL	36,085	23,474,847	847,089.9	2,950,959	3.81	81.78
B.B.#4 (GAS)	185	8,292	6.2	34.7	27.8	-	GAS	83,278	1,020,000	84,944.1	291,481	3.52	3.50
BIG BEND #4 TOTAL	**437**	**85,720**	**27.2**	**34.7**	**57.1**	**10,955**	**-**	**-**	**-**	**932,034.0**	**3,242,440**	**3.78**	**-**
B.B. IGNITION	-	-	-	-	-	-	GAS	31,053	0	31,674.0	108,688	-	3.50
BIG BEND CT #4 TOTAL	**56**	**0**	**0.0**	**0.9**	**0.0**	**0**	**GAS**	**0**	**1,020,000**	**0.0**	**0**	**0.00**	**0.00**
BIG BEND STATION TOTAL	**1,483**	**351,140**	**32.9**	**58.8**	**32.9**	**12,478**	**-**	**-**	**-**	**4,386,534.8**	**15,205,057**	**4.33**	**-**
POLK #1 GASIFIER [3]	220	(1,924)	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
POLK #1 CT (GAS)	150	74,100	68.2	100.0	71.0	11,930	GAS	866,646	1,020,000	883,979.0	3,033,325	2.87	3.50
POLK #1 ST	85	31,448	51.1	100.0	53.3	0		-	-	-	-	-	-
POLK #1 TOTAL	**235**	**103,624**	**62.0**	**100.0**	**64.5**	**8,531**	**-**	**-**	**-**	**883,979.0**	**3,033,325**	**2.93**	**-**
POLK #2 ST DUCT FIRING	120	791	0.9	-	69.8	8,403	GAS	6,517	1,020,000	6,647.0	22,809	2.88	3.50
POLK #2 ST W/O DUCT FIRING	341	68,283	27.8	-	-	-		-	-	-	-	-	-
POLK #2 ST TOTAL	**461**	**69,074**	**20.5**	**55.0**	**69.8**	**-**	**GAS**	**-**	**-**	**6,647.0**	**22,809**	**0.03**	**-**
POLK #2 CT (GAS)	150	44,830	41.4	73.0	88.9	11,255	GAS	494,666	1,020,000	504,559.0	1,731,366	3.86	3.50
POLK #2 CT (OIL)	159	0	0.0	73.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**150**	**44,830**	**41.4**	**73.0**	**88.9**	**11,255**	**-**	**-**	**-**	**504,559.0**	**1,731,366**	**3.86**	**-**
POLK #3 CT (GAS)	150	23,098	21.3	68.7	85.4	11,436	GAS	258,970	1,020,000	264,149.0	906,412	3.92	3.50
POLK #3 CT (OIL)	159	0	0.00	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**150**	**23,098**	**21.3**	**68.7**	**85.4**	**11,436**	**-**	**-**	**-**	**264,149.0**	**906,412**	**3.92**	**-**
POLK #4 TOTAL	**150**	**39,281**	**36.2**	**75.2**	**86.1**	**11,142**	GAS	**429,097**	**1,020,000**	**437,679.0**	**1,501,871**	**3.82**	**3.50**
POLK #5 TOTAL	**150**	**37,617**	**34.8**	**68.3**	**90.7**	**11,008**	GAS	**405,973**	**1,020,000**	**414,092.0**	**1,420,934**	**3.78**	**3.50**
POLK #2 CC TOTAL	**1,061**	**213,900**	**27.8**	**64.2**	**50.6**	**7,607**	GAS	**-**	**-**	**1,627,126.0**	**5,583,392**	**2.61**	**-**
POLK STATION TOTAL	**1,296**	**317,524**	**34.0**	**70.7**	**35.4**	**7,908**	**-**	**-**	**-**	**2,511,105.0**	**8,616,717**	**2.71**	**-**

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2019

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1	233	100,163	59.7	81.4	73.2	-		-	-	-	-	-	-
BAYSIDE CT1A	156	62,282	55.5	89.0	83.1	11,358	GAS	693,516	1,020,000	707,385.9	2,428,352	3.90	3.50
BAYSIDE CT1B	156	59,113	52.6	91.9	83.3	11,353	GAS	657,979	1,020,000	671,138.4	2,303,918	3.90	3.50
BAYSIDE CT1C	156	63,935	56.9	92.7	81.2	11,163	GAS	699,737	1,020,000	713,731.4	2,450,134	3.83	3.50
BAYSIDE UNIT 1 TOTAL	**701**	**285,493**	**56.6**	**87.9**	**69.4**	**7,329**	**GAS**	**2,051,232**	**1,020,000**	**2,092,255.7**	**7,182,404**	**2.52**	**3.50**
BAYSIDE ST 2	305	169,796	77.3	93.8	77.7	-		-	-	-	-	-	-
BAYSIDE CT2A	156	81,878	72.9	100.0	85.4	10,985	GAS	881,786	1,020,000	899,421.5	3,087,582	3.77	3.50
BAYSIDE CT2B	156	73,714	65.6	100.0	84.6	11,214	GAS	810,403	1,020,000	826,611.5	2,837,634	3.85	3.50
BAYSIDE CT2C	156	94,914	84.5	100.0	84.5	11,274	GAS	1,049,099	1,020,000	1,070,081.2	3,673,431	3.87	3.50
BAYSIDE CT2D	156	71,903	64.0	77.1	84.8	11,201	GAS	789,601	1,020,000	805,393.2	2,764,796	3.85	3.50
BAYSIDE UNIT 2 TOTAL	**929**	**492,205**	**73.6**	**94.1**	**73.6**	**7,317**	**GAS**	**3,530,889**	**1,020,000**	**3,601,507.5**	**12,363,443**	**2.51**	**3.50**
BAYSIDE UNIT 3 TOTAL	**56**	**503**	**1.2**	**94.1**	**92.1**	**11,069**	**GAS**	**5,459**	**1,020,000**	**5,567.9**	**19,114**	**3.80**	**3.50**
BAYSIDE UNIT 4 TOTAL	**56**	**749**	**1.9**	**85.2**	**105.6**	**10,553**	**GAS**	**7,749**	**1,020,000**	**7,904.1**	**27,133**	**3.62**	**3.50**
BAYSIDE UNIT 5 TOTAL	**56**	**968**	**2.4**	**88.7**	**95.4**	**11,350**	**GAS**	**10,771**	**1,020,000**	**10,986.8**	**37,716**	**3.90**	**3.50**
BAYSIDE UNIT 6 TOTAL	**56**	**692**	**1.7**	**88.3**	**100.6**	**10,728**	**GAS**	**7,278**	**1,020,000**	**7,423.8**	**25,485**	**3.68**	**3.50**
BAYSIDE STATION TOTAL	**1,854**	**780,610**	**58.5**	**91.2**	**58.5**	**7,335**	**GAS**	**5,613,378**	**1,020,000**	**5,725,645.6**	**19,655,295**	**2.52**	**3.50**
SYSTEM	**5,078**	**1,529,962**	**42.2**	**75.1**	**44.1**	**8,247**	**-**	**-**	**-**	**12,623,285.5**	**43,477,069**	**2.84**	**-**

LEGEND:
B.B. = BIG BEND **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM TURBINE**

Footnotes:
[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] Station Service

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2019

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR	1.6	323	27.1	-	43.2	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR	19.4	4,508	31.2	-	63.4	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR	1.5	247	22.1	-	44.5	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR	70.3	12,009	23.0	-	47.7	-	SOLAR	-	-	-	-	-	-
BALM SOLAR	74.4	12,908	23.3	-	48.7	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR	74.5	4,335	7.8	-	35.3	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR	61.1	12,026	26.5	-	54.3	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR	55.4	11,736	28.5	-	60.6	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR	37.5	9,119	32.7	-	65.0	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK	49.5	11,242	30.5	-	57.7	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL	**445.2**	**78,453**	**23.7**	-	**37.8**	-	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
BIG BEND #1 TOTAL	**305**	**61,574**	**27.1**	**96.5**	**42.7**	**13,901**	**GAS**	**838,350**	**1,021,000**	**855,955.1**	**2,852,112**	**4.63**	**3.40**
BIG BEND #2 TOTAL	**340**	**111,926**	**44.2**	**99.9**	**44.2**	**12,764**	**GAS**	**1,399,285**	**1,021,000**	**1,428,670.6**	**4,760,449**	**4.25**	**3.40**
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	37,128	14.5	41.6	68.2	-	GAS	382,911	1,021,000	390,951.8	1,302,684	3.51	3.40
BIG BEND #3 TOTAL	**345**	**37,128**	**14.5**	**41.6**	**68.2**	**10,530**	**-**	**-**	**-**	**390,951.8**	**1,302,684**	**3.51**	**-**
B.B.#4 (COAL)	437	135,386	41.6	26.1	58.6	-	COAL	65,724	23,101,025	1,518,291.8	4,953,944	3.66	75.37
B.B.#4 (GAS)	185	2,549	1.9	26.1	55.1	-	GAS	28,362	1,021,000	28,957.6	96,491	3.79	3.40
BIG BEND #4 TOTAL	**437**	**137,935**	**42.4**	**26.1**	**57.0**	**11,217**	**-**	**-**	**-**	**1,547,249.4**	**5,050,435**	**3.66**	**-**
B.B. IGNITION	-	-	-	-	-	-	GAS	30,418	0	31,057.0	103,484	-	3.40
BIG BEND CT #4 TOTAL	**61**	**102**	**0.2**	**89.0**	**37.2**	**27,295**	**GAS**	**2,727**	**1,021,000**	**2,784.1**	**9,277**	**9.10**	**3.40**
BIG BEND STATION TOTAL	**1,488**	**348,665**	**31.5**	**63.5**	**31.5**	**12,119**	**-**	**-**	**-**	**4,225,611.0**	**14,078,441**	**4.04**	**-**
POLK #1 GASIFIER [3]	220	(2,370)	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
POLK #1 CT (GAS)	150	54,244	47.1	69.1	69.7	12,118	GAS	643,795	1,021,000	657,315.0	2,190,228	2.82	3.40
POLK #1 ST	85	23,415	35.9	68.4	52.5	0		-	-	-	-	-	-
POLK #1 TOTAL	**235**	**75,289**	**43.1**	**68.9**	**62.9**	**8,731**	**-**	**-**	**-**	**657,315.0**	**2,190,228**	**2.91**	**-**
POLK #2 ST DUCT FIRING	120	15,731	17.6	-	86.5	8,400	GAS	129,427	1,021,000	132,145.0	440,318	2.80	3.40
POLK #2 ST W/O DUCT FIRING	341	181,164	71.4	-	-	-		-	-	-	-	-	-
POLK #2 ST TOTAL	**461**	**196,895**	**57.4**	**99.1**	**86.5**	**-**	**GAS**	**-**	**-**	**132,145.0**	**440,318**	**0.22**	**-**
POLK #2 CT (GAS)	150	74,786	67.1	100.0	89.9	11,301	GAS	827,738	1,021,000	845,121.0	2,816,013	3.77	3.40
POLK #2 CT (OIL)	159	67	0.1	100.0	34.2	11,558	LGT.OIL	133	5,830	778.8	17,030	25.42	128.05
POLK #2 TOTAL	**150**	**74,853**	**67.1**	**100.0**	**89.9**	**11,290**	**-**	**-**	**-**	**845,899.8**	**2,833,043**	**3.78**	**-**
POLK #3 CT (GAS)	150	79,495	71.2	98.9	92.2	11,227	GAS	874,129	1,021,000	892,486.0	2,973,837	3.74	3.40
POLK #3 CT (OIL)	159	0	0.00	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**150**	**79,495**	**71.2**	**98.9**	**92.2**	**11,227**	**-**	**-**	**-**	**892,486.0**	**2,973,837**	**3.74**	**-**
POLK #4 TOTAL	**150**	**87,460**	**78.4**	**100.0**	**94.4**	**10,939**	GAS	**937,018**	**1,021,000**	**956,695.0**	**3,187,786**	**3.64**	**3.40**
POLK #5 TOTAL	**150**	**78,560**	**70.4**	**100.0**	**93.4**	**10,985**	GAS	**845,257**	**1,021,000**	**863,007.0**	**2,875,610**	**3.66**	**3.40**
POLK #2 CC TOTAL	**1,061**	**517,264**	**65.5**	**99.4**	**65.5**	**7,133**	GAS	**-**	**-**	**3,690,232.8**	**12,310,594**	**2.38**	**-**
POLK STATION TOTAL	**1,296**	**592,553**	**61.5**	**93.9**	**61.5**	**7,336**	**-**	**-**	**-**	**4,347,547.8**	**14,500,822**	**2.45**	**-**

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2019

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1	233	125,774	72.6	93.9	72.6	-		-	-	-	-	-	-
BAYSIDE CT1A	156	67,968	58.6	82.9	82.1	11,444	GAS	761,814	1,021,000	777,812.2	2,592,535	3.81	3.40
BAYSIDE CT1B	156	76,811	66.2	99.0	82.8	11,397	GAS	857,430	1,021,000	875,436.1	2,917,927	3.80	3.40
BAYSIDE CT1C	156	87,041	75.0	100.0	82.3	11,148	GAS	950,364	1,021,000	970,321.5	3,234,191	3.72	3.40
BAYSIDE UNIT 1 TOTAL	**701**	**357,594**	**68.6**	**93.9**	**68.6**	**7,337**	**GAS**	**2,569,608**	**1,021,000**	**2,623,569.8**	**8,744,653**	**2.45**	**3.40**
BAYSIDE ST 2	305	192,840	85.0	99.6	85.0	-		-	-	-	-	-	-
BAYSIDE CT2A	156	87,144	75.1	98.9	101.1	11,052	GAS	943,342	1,021,000	963,152.1	3,210,295	3.68	3.40
BAYSIDE CT2B	156	77,535	66.8	99.6	84.3	11,233	GAS	853,008	1,021,000	870,921.4	2,902,878	3.74	3.40
BAYSIDE CT2C	156	97,023	83.6	100.0	83.6	11,351	GAS	1,078,615	1,021,000	1,101,266.5	3,670,644	3.78	3.40
BAYSIDE CT2D	183	96,937	71.2	100.0	71.2	11,295	GAS	1,072,344	1,021,000	1,094,862.9	3,649,302	3.76	3.40
BAYSIDE UNIT 2 TOTAL	**956**	**551,479**	**77.5**	**99.6**	**77.5**	**7,308**	**GAS**	**3,947,309**	**1,021,000**	**4,030,202.8**	**13,433,119**	**2.44**	**3.40**
BAYSIDE UNIT 3 TOTAL	**56**	**257**	**0.6**	**97.8**	**84.5**	**11,803**	**GAS**	**2,971**	**1,021,000**	**3,033.3**	**10,110**	**3.93**	**3.40**
BAYSIDE UNIT 4 TOTAL	**56**	**210**	**0.5**	**97.6**	**89.9**	**11,221**	**GAS**	**2,308**	**1,021,000**	**2,356.5**	**7,854**	**3.74**	**3.40**
BAYSIDE UNIT 5 TOTAL	**56**	**324**	**0.8**	**97.6**	**75.3**	**11,933**	**GAS**	**3,787**	**1,021,000**	**3,866.3**	**12,887**	**3.98**	**3.40**
BAYSIDE UNIT 6 TOTAL	**56**	**337**	**0.8**	**97.2**	**89.7**	**11,039**	**GAS**	**3,644**	**1,021,000**	**3,720.2**	**12,400**	**3.68**	**3.40**
BAYSIDE STATION TOTAL	**1,881**	**910,201**	**65.0**	**97.3**	**65.0**	**7,324**	**GAS**	**6,529,627**	**1,021,000**	**6,666,748.9**	**22,221,023**	**2.44**	**3.40**
SYSTEM	**5,110**	**1,929,872**	**50.8**	**85.6**	**52.5**	**7,896**	**-**	**-**	**-**	**15,239,907.6**	**50,800,286**	**2.63**	**-**

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] Station Service

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2019

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) (2)	(L) AS BURNED FUEL COST ($) (1)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
TIA SOLAR		1.6	275	23.9	-	42.4	-	SOLAR	-	-	-	-	-	-
BIG BEND SOLAR		19.4	4,241	30.4	-	53.6	-	SOLAR	-	-	-	-	-	-
LEGOLAND SOLAR		1.5	207	19.2	-	36.9	-	SOLAR	-	-	-	-	-	-
PAYNE CREEK SOLAR		70.3	9,118	18.0	-	36.8	-	SOLAR	-	-	-	-	-	-
BALM SOLAR		74.4	11,322	21.1	-	42.4	-	SOLAR	-	-	-	-	-	-
LITHIA SOLAR		74.5	8,988	16.8	-	34.2	-	SOLAR	-	-	-	-	-	-
GRANGE HALL SOLAR		61.1	9,403	21.4	-	42.4	-	SOLAR	-	-	-	-	-	-
PEACE CREEK SOLAR		55.4	7,370	18.5	-	37.3	-	SOLAR	-	-	-	-	-	-
BONNIE MINE SOLAR		37.5	7,262	26.9	-	51.5	-	SOLAR	-	-	-	-	-	-
LAKE HANCOCK SOLAR		49.6	7,556	21.2	-	38.2	-	SOLAR	-	-	-	-	-	-
SOLAR TOTAL		**445.3**	**65,742**	**20.5**	-	**36.1**	-	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
BIG BEND #1 TOTAL	(4)	**305**	**86,621**	**39.4**	**98.0**	**47.2**	**13,930**	**GAS**	**1,281,084**	**1,024,000**	**1,311,419.6**	**4,505,099**	**5.20**	**3.52**
BIG BEND #2 TOTAL	(4)	**340**	**25,535**	**10.4**	**82.0**	**46.8**	**12,478**	**GAS**	**371,925**	**1,024,000**	**380,607.7**	**1,308,082**	**5.12**	**3.52**
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)	(4)	345	0	0.0	0.0	0.0	-	GAS	(175,473)	0	(178,982.3)	(612,568)	0.00	3.49
BIG BEND #3 TOTAL		**345**	**0**	**0.0**	**0.0**	**0.0**	**0**	**-**	**-**	**-**	**(178,982.3)**	**(612,568)**	**0.00**	**-**
B.B.#4 (COAL)		437	151,415	48.1	65.7	67.8	-	COAL	68,443	23,012,211	1,575,024.7	5,199,023	3.43	75.96
B.B.#4 (GAS)	(4)	185	1,394	1.0	65.7	376.8	-	GAS	21,248	1,024,000	21,730.1	74,739	5.36	3.52
BIG BEND #4 TOTAL		**437**	**152,809**	**48.6**	**65.7**	**68.1**	**10,403**	**-**	**-**	**-**	**1,596,754.8**	**5,273,762**	**3.45**	**-**
B.B. IGNITION	(4)	-	-	-	-	-	-	GAS	22,034	0	22,563.0	77,523	-	3.52
BIG BEND CT #4 TOTAL		**56**	**573**	**1.4**	**100.0**	**65.6**	**13,008**	**GAS**	**7,279**	**1,024,000**	**7,453.6**	**25,595**	**4.47**	**3.52**
BIG BEND STATION TOTAL		**1,483**	**265,538**	**26.5**	**61.9**	**31.7**	**11,759**	**-**	**-**	**-**	**3,117,253.4**	**10,577,493**	**3.98**	**-**
POLK #1 GASIFIER	(3)	220	(755)	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
POLK #1 CT (GAS)	(4)	150	71,673	65.9	98.9	71.1	12,178	GAS	852,369	1,024,000	872,826.0	2,998,387	2.95	3.52
POLK #1 ST		85	30,117	48.8	97.8	108.2	0		-	-	-	-	-	-
POLK #1 TOTAL		**235**	**101,035**	**59.7**	**98.5**	**64.4**	**8,639**	**-**	**-**	**-**	**872,826.0**	**2,998,387**	**2.97**	**-**
POLK #2 ST DUCT FIRING	(4)	120	13,643	15.8	-	67.5	8,400	GAS	111,910	1,024,000	114,596.0	393,503	2.88	3.52
POLK #2 ST W/O DUCT FIRING		341	156,635	63.8	-	-	-		-	-	-	-	-	-
POLK #2 ST TOTAL		**461**	**170,278**	**51.3**	**79.4**	**67.5**	**-**	**GAS**	**-**	**-**	**114,596.0**	**393,503**	**0.23**	**-**
POLK #2 CT (GAS)	(4)	150	17,744	16.4	24.4	87.6	11,463	GAS	198,634	1,024,000	203,401.0	699,186	3.94	3.52
POLK #2 CT (OIL)	(5)	159	0	0.0	24.4	0.0	0	LGT.OIL	95	5,830	550.3	12,035	0.00	126.68
POLK #2 TOTAL		**150**	**17,744**	**16.4**	**24.4**	**87.6**	**11,494**	**-**	**-**	**-**	**203,951.3**	**711,221**	**4.01**	**-**
POLK #3 CT (GAS)	(4)	150	95,922	88.8	100.0	93.2	11,221	GAS	1,051,079	1,024,000	1,076,305.0	3,696,147	3.85	3.52
POLK #3 CT (OIL)		159	0	0.00	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL		**150**	**95,922**	**88.8**	**100.0**	**93.2**	**11,221**	**-**	**-**	**-**	**1,076,305.0**	**3,696,147**	**3.85**	**-**
POLK #4 TOTAL	(4)	**150**	**87,506**	**81.0**	**100.0**	**95.6**	**10,947**	GAS	**935,481**	**1,024,000**	**957,933.0**	**3,289,950**	**3.76**	**3.52**
POLK #5 TOTAL	(4)	**150**	**78,329**	**72.5**	**100.0**	**94.0**	**10,988**	GAS	**840,478**	**1,024,000**	**860,650.0**	**2,955,870**	**3.77**	**3.52**
POLK #2 CC TOTAL		**1,061**	**449,779**	**58.9**	**80.4**	**58.9**	**7,144**	GAS	**-**	**-**	**3,213,435.3**	**11,046,691**	**2.46**	**-**
POLK STATION TOTAL		**1,296**	**550,814**	**59.0**	**83.6**	**59.0**	**7,419**	**-**	**-**	**-**	**4,086,261.3**	**14,045,078**	**2.55**	**-**

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2019

(A) PLANT/UNIT		(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
BAYSIDE ST 1		233	131,840	78.6	94.6	78.6	-		-	-	-	-	-	-
BAYSIDE CT1A		156	83,961	74.8	100.0	80.7	11,391	GAS	933,963	1,024,000	956,377.7	3,286,069	3.91	3.52
BAYSIDE CT1B		156	87,794	78.2	100.0	81.0	11,389	GAS	976,414	1,024,000	999,848.4	3,435,430	3.91	3.52
BAYSIDE CT1C		156	67,693	60.3	87.3	80.9	11,127	GAS	735,554	1,024,000	753,207.3	2,587,984	3.82	3.52
BAYSIDE UNIT 1 TOTAL	(4)	**701**	**371,288**	**73.6**	**95.4**	**73.6**	**7,297**	**GAS**	**2,645,931**	**1,024,000**	**2,709,433.4**	**9,309,483**	**2.51**	**3.52**
BAYSIDE ST 2		305	189,572	86.3	99.0	86.3	-		-	-	-	-	-	-
BAYSIDE CT2A		156	84,385	75.1	100.0	84.6	10,995	GAS	906,072	1,024,000	927,817.9	3,188,149	3.78	3.52
BAYSIDE CT2B		156	83,464	74.3	100.0	83.4	11,167	GAS	910,179	1,024,000	932,022.9	3,202,600	3.84	3.52
BAYSIDE CT2C		156	88,347	78.7	97.7	83.0	11,286	GAS	973,700	1,024,000	997,069.0	3,426,108	3.88	3.52
BAYSIDE CT2D		156	92,666	82.5	100.0	82.7	11,239	GAS	1,017,085	1,024,000	1,041,494.9	3,578,765	3.86	3.52
BAYSIDE UNIT 2 TOTAL	(4)	**929**	**538,434**	**80.5**	**99.3**	**80.5**	**7,240**	**GAS**	**3,807,036**	**1,024,000**	**3,898,404.6**	**13,395,622**	**2.49**	**3.52**
BAYSIDE UNIT 3 TOTAL	(4)	**56**	**70**	**0.2**	**100.0**	**88.3**	**11,286**	**GAS**	**768**	**1,024,000**	**786.6**	**2,710**	**3.87**	**3.53**
BAYSIDE UNIT 4 TOTAL	(4)	**56**	**0**	**0.0**	**100.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**12**	**0.00**	**0.00**
BAYSIDE UNIT 5 TOTAL	(4)	**56**	**1,514**	**3.8**	**98.6**	**86.7**	**11,578**	**GAS**	**17,119**	**1,024,000**	**17,530.1**	**60,229**	**3.98**	**3.52**
BAYSIDE UNIT 6 TOTAL	(4)	**56**	**416**	**1.0**	**98.6**	**85.7**	**11,152**	**GAS**	**4,533**	**1,024,000**	**4,641.4**	**15,953**	**3.83**	**3.52**
BAYSIDE STATION TOTAL		**1,854**	**911,722**	**68.3**	**97.8**	**68.3**	**7,273**	**GAS**	**6,475,387**	**1,024,000**	**6,630,796.2**	**22,784,009**	**2.50**	**3.52**
SYSTEM		**5,078**	**1,793,816**	**49.1**	**82.3**	**53.7**	**7,715**	**-**	**-**	**-**	**13,834,310.9**	**47,406,580**	**2.64**	**-**

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] Station Service
[4] Includes April 2019 adjustments to Big Bend, Polk and Bayside Stations, details on Schedule A5 page 2.
[5] Net generation MWh rounded to zero due to unit running only 1 service hour.

Docket No. 20190001-EI
Exhibit No. PAR-2
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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2019

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,390	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	270	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	10,720	20.9	-	20.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	10,950	20.2	-	20.2	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	12,090	22.3	-	22.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	9,150	20.6	-	20.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	7,470	18.5	-	18.5	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,540	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	6,930	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
11. SOLAR TOTAL [3]	**436.2**	**70,760**	**21.8**	**-**	**21.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
12. BIG BEND #1 TOTAL	**305**	**0**	**0.0**	**91.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
13. BIG BEND #2 TOTAL	**340**	**12,990**	**5.1**	**91.9**	**37.5**	**12,202**	**GAS**	**154,180**	**1,028,019**	**158,500.0**	**601,429**	**4.63**	**3.90**
14. B.B.#3 (GAS)	345	13,470	5.2	-	-	-	GAS	149,450	1,028,036	153,640.0	582,978	4.33	3.90
15. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
16. BIG BEND #3 TOTAL	**395**	**13,470**	**4.6**	**89.5**	**47.4**	**11,406**		**-**	**-**	**153,640.0**	**582,978**	**4.33**	**-**
17. B.B.#4 (GAS)	185	5,700	4.1	-	-	-	GAS	70,950	1,028,048	72,940.0	276,763	4.86	3.90
18. B.B.#4 (COAL)	437	108,360	33.3	-	-	-	COAL	61,590	22,500,731	1,385,820.0	4,658,228	4.30	75.63
19. BIG BEND #4 TOTAL	**437**	**114,060**	**35.1**	**75.6**	**39.2**	**12,789**		**-**	**-**	**1,458,760.0**	**4,934,991**	**4.33**	**-**
20. B.B. IGNITION	-	-	-	-	-	-	GAS	17,530	-	18,020.0	68,381	-	3.90
21. B.B.C.T.#4 TOTAL	**56**	**390**	**0.9**	**98.2**	**99.5**	**11,718**	**GAS**	**4,440**	**1,029,279**	**4,570.0**	**17,320**	**4.44**	**3.90**
22. BIG BEND STATION TOTAL	**1,533**	**140,910**	**12.4**	**86.9**	**39.7**	**12,600**	**-**	**-**	**-**	**1,775,470.0**	**6,205,099**	**4.40**	**-**
23. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
24. POLK #1 CT (GAS)	210	67,380	43.1	-	87.2	8,352	GAS	547,420	1,027,986	562,740.0	2,135,388	3.17	3.90
25. POLK #1 TOTAL	**220**	**67,380**	**41.2**	**92.5**	**87.2**	**8,352**	**-**	**-**	**-**	**562,740.0**	**2,135,388**	**3.17**	**-**
26. POLK #2 ST DUCT FIRING	120	18,300	20.5	-	79.0	8,277	GAS	147,340	1,028,030	151,470.0	574,747	3.14	3.90
27. POLK #2 ST W/O DUCT FIRING	341	566,311	-	-	-	-	GAS	3,904,442	1,028,010	4,013,805.7	15,230,530	2.69	3.90
28. POLK #2 ST TOTAL	**461**	**584,611**	**170.4**	**-**	**136.8**	**7,125**	**GAS**	**-**	**-**	**4,165,275.7**	**15,805,277**	**2.70**	**-**
29. POLK #2 CT (GAS)	150	1,500	1.3	-	100.0	11,453	GAS	16,720	1,027,512	17,180.0	65,221	4.35	3.90
30. POLK #2 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
31. POLK #2 TOTAL [4]	**150**	**2,164**	**1.9**	**-**	**98.2**	**11,316**	**-**	**-**	**-**	**24,487.1**	**224,100**	**10.36**	**-**
32. POLK #3 CT (GAS)	150	1,500	1.3	-	100.0	11,453	GAS	16,720	1,027,512	17,180.0	65,222	4.35	3.90
33. POLK #3 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
34. POLK #3 TOTAL [4]	**150**	**2,164**	**1.9**	**-**	**98.2**	**11,316**	**-**	**-**	**-**	**24,487.1**	**224,100**	**10.36**	**-**
35. POLK #4 CT (GAS) TOTAL [4]	**150**	**1,200**	**1.1**	**-**	**100.0**	**11,475**	**GAS**	**13,390**	**1,028,379**	**13,770.0**	**52,232**	**4.35**	**3.90**
36. POLK #5 CT (GAS) TOTAL [4]	**150**	**1,200**	**1.1**	**-**	**100.0**	**11,475**	**GAS**	**13,390**	**1,028,379**	**13,770.0**	**52,232**	**4.35**	**3.90**
37. POLK #2 CC TOTAL	**1,061**	**591,339**	**74.9**	**98.2**	**135.0**	**7,173**	**-**	**-**	**-**	**4,241,789.9**	**16,357,941**	**2.77**	**-**
38. POLK STATION TOTAL	**1,281**	**658,719**	**69.1**	**97.2**	**121.9**	**7,294**	**-**	**-**	**-**	**4,804,529.9**	**18,493,329**	**2.81**	**-**
39. BAYSIDE #1	701	439,670	84.3	97.2	87.0	7,296	GAS	3,120,380	1,027,997	3,207,740.0	12,172,044	2.77	3.90
40. BAYSIDE #2	929	519,270	75.1	97.5	78.0	7,391	GAS	3,733,240	1,027,997	3,837,760.0	14,562,702	2.80	3.90
41. BAYSIDE #3	56	2,050	4.9	98.6	91.5	11,756	GAS	23,440	1,028,157	24,100.0	91,435	4.46	3.90
42. BAYSIDE #4	56	890	2.1	98.6	93.5	11,910	GAS	10,320	1,027,132	10,600.0	40,256	4.52	3.90
43. BAYSIDE #5	56	3,440	8.3	98.6	89.0	11,654	GAS	39,000	1,027,949	40,090.0	152,132	4.42	3.90
44. BAYSIDE #6	56	2,580	6.2	98.6	92.1	11,636	GAS	29,200	1,028,082	30,020.0	113,904	4.41	3.90
45. BAYSIDE STATION TOTAL	**1,854**	**967,900**	**70.2**	**97.5**	**81.9**	**7,387**	**GAS**	**6,955,580**	**1,027,996**	**7,150,310.0**	**27,132,473**	**2.80**	**3.90**
46. SYSTEM TOTAL	**5,104**	**1,838,289**	**48.4**	**85.9**	**96.9**	**7,469**	**-**	**-**	**-**	**13,730,309.9**	**51,830,901**	**2.82**	**-**

LEGEND:
B.B. = BIG BEND **CC = COMBINED CYCLE**
CT = COMBUSTION TURBINE **ST = STEAM TURBINE**

[1] As burned fuel cost system total includes ignitio
[2] Fuel burned (MM BTU) system total excludes ignitio
[3] AC rating
[4] In Simple Cycle Mode

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2019

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,250	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	11,180	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	11,320	20.9	-	20.9	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	11,930	22.0	-	22.0	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	9,420	21.2	-	21.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	8,730	21.6	-	21.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,410	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	7,630	21.0	-	21.0	-	SOLAR	-	-	-	-	-	-
11. SOLAR TOTAL [3]	**436.2**	**73,370**	**22.6**	**-**	**22.6**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
12. BIG BEND #1 TOTAL	**305**	**15,360**	**6.8**	**91.9**	**38.2**	**13,790**	**GAS**	**206,040**	**1,028,004**	**211,810.0**	**808,418**	**5.26**	**3.92**
13. BIG BEND #2 TOTAL	**340**	**23,240**	**9.2**	**91.9**	**41.7**	**11,854**	**GAS**	**267,980**	**1,028,024**	**275,490.0**	**1,051,445**	**4.52**	**3.92**
14. B.B.#3 (GAS)	345	48,850	19.0	-	-	-	GAS	538,040	1,028,009	553,110.0	2,111,051	4.32	3.92
15. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
16. BIG BEND #3 TOTAL	**395**	**48,850**	**16.6**	**89.5**	**48.9**	**11,323**		**-**	**-**	**553,110.0**	**2,111,051**	**4.32**	**-**
17. B.B.#4 (GAS)	185	5,800	4.2	-	-	-	GAS	71,790	1,027,998	73,800.0	281,675	4.86	3.92
18. B.B.#4 (COAL)	437	110,260	33.9	-	-	-	COAL	62,320	22,498,716	1,402,120.0	4,693,519	4.26	75.31
19. BIG BEND #4 TOTAL	**437**	**116,060**	**35.7**	**75.6**	**39.9**	**12,717**		**-**	**-**	**1,475,920.0**	**4,975,194**	**4.29**	**-**
20. B.B. IGNITION	-	-	-	-	-	-	GAS	46,750	-	48,060.0	183,428	-	3.92
21. B.B.C.T.#4 TOTAL	**56**	**550**	**1.3**	**98.2**	**98.2**	**11,600**	**GAS**	**6,210**	**1,027,375**	**6,380.0**	**24,366**	**4.43**	**3.92**
22. BIG BEND STATION TOTAL	**1,533**	**204,060**	**17.9**	**86.9**	**41.9**	**12,363**	**-**	**-**	**-**	**2,522,710.0**	**9,153,902**	**4.49**	**-**
23. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
24. POLK #1 CT (GAS)	210	47,640	30.5	-	89.3	8,336	GAS	386,290	1,028,036	397,120.0	1,515,646	3.18	3.92
25. POLK #1 TOTAL	**220**	**47,640**	**29.1**	**92.5**	**89.3**	**8,336**	**-**	**-**	**-**	**397,120.0**	**1,515,646**	**3.18**	**-**
26. POLK #2 ST DUCT FIRING	120	18,130	20.3	-	81.7	8,272	GAS	145,890	1,027,966	149,970.0	572,413	3.16	3.92
27. POLK #2 ST W/O DUCT FIRING	341	560,331	-	-	-	-	GAS	3,861,112	1,028,011	3,969,265.7	15,149,443	2.70	3.92
28. POLK #2 ST TOTAL	**461**	**578,461**	**168.7**	**-**	**136.5**	**7,121**	**GAS**	**-**	**-**	**4,119,235.7**	**15,721,856**	**2.72**	**-**
29. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. POLK #2 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
31. POLK #2 TOTAL [4]	**150**	**664**	**0.6**	**-**	**94.3**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,879**	**23.93**	**-**
32. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
33. POLK #3 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
34. POLK #3 TOTAL [4]	**150**	**664**	**0.6**	**-**	**94.3**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,878**	**23.93**	**-**
35. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
36. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #2 CC TOTAL	**1,061**	**579,789**	**73.4**	**98.2**	**136.1**	**7,130**	**-**	**-**	**-**	**4,133,849.9**	**16,039,613**	**2.77**	**-**
38. POLK STATION TOTAL	**1,281**	**627,429**	**65.8**	**97.2**	**126.1**	**7,221**	**-**	**-**	**-**	**4,530,969.9**	**17,555,259**	**2.80**	**-**
39. BAYSIDE #1	701	440,020	84.4	97.2	87.1	7,295	GAS	3,122,570	1,027,999	3,210,000.0	12,251,702	2.78	3.92
40. BAYSIDE #2	929	513,810	74.3	97.5	77.2	7,394	GAS	3,695,530	1,028,001	3,799,010.0	14,499,766	2.82	3.92
41. BAYSIDE #3	56	1,710	4.1	98.6	89.8	11,918	GAS	19,820	1,028,254	20,380.0	77,766	4.55	3.92
42. BAYSIDE #4	56	1,020	2.4	98.6	95.9	11,755	GAS	11,670	1,027,421	11,990.0	45,788	4.49	3.92
43. BAYSIDE #5	56	2,850	6.8	98.6	82.1	11,912	GAS	33,020	1,028,165	33,950.0	129,557	4.55	3.92
44. BAYSIDE #6	56	2,160	5.2	98.6	91.8	11,731	GAS	24,650	1,027,992	25,340.0	96,717	4.48	3.92
45. BAYSIDE STATION TOTAL	**1,854**	**961,570**	**69.7**	**97.5**	**81.5**	**7,384**	**GAS**	**6,907,260**	**1,028,001**	**7,100,670.0**	**27,101,296**	**2.82**	**3.92**
46. SYSTEM TOTAL	**5,104**	**1,866,429**	**49.1**	**85.9**	**93.5**	**7,584**	**-**	**-**	**-**	**14,154,349.9**	**53,810,457**	**2.88**	**-**

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
CC = COMBINED CYCLE
ST = STEAM TURBINE

[1] As burned fuel cost system total includes ignitio
[2] Fuel burned (MM BTU) system total excludes ignitio
[3] AC rating
[4] In Simple Cycle Mode

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2019

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	220	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,500	25.3	-	25.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	210	20.8	-	20.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	11,510	23.2	-	23.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	10,810	20.6	-	20.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	10,690	20.4	-	20.4	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	8,690	20.2	-	20.2	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	8,270	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	6,800	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	7,500	21.3	-	21.3	-	SOLAR	-	-	-	-	-	-
11. SOLAR TOTAL [3]	**436.2**	**68,200**	**21.7**	**-**	**21.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
12. BIG BEND #1 TOTAL	**305**	**6,760**	**3.1**	**91.9**	**36.9**	**13,948**	**GAS**	**91,720**	**1,028,020**	**94,290.0**	**357,178**	**5.28**	**3.89**
13. BIG BEND #2 TOTAL	**340**	**14,230**	**5.8**	**91.9**	**35.8**	**12,370**	**GAS**	**171,230**	**1,027,974**	**176,020.0**	**666,807**	**4.69**	**3.89**
14. B.B.#3 (GAS)	345	20,510	8.3	-	-	-	GAS	226,790	1,027,999	233,140.0	883,170	4.31	3.89
15. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
16. BIG BEND #3 TOTAL	**395**	**20,510**	**7.2**	**89.5**	**48.1**	**11,367**		**-**	**-**	**233,140.0**	**883,170**	**4.31**	**-**
17. B.B.#4 (GAS)	185	2,840	2.1	-	-	-	GAS	34,970	1,028,024	35,950.0	136,181	4.80	3.89
18. B.B.#4 (COAL)	437	53,950	17.1	-	-	-	COAL	30,360	22,498,024	683,040.0	2,238,624	4.15	73.74
19. BIG BEND #4 TOTAL	**437**	**56,790**	**18.0**	**37.8**	**40.4**	**12,661**		**-**	**-**	**718,990.0**	**2,374,805**	**4.18**	**-**
20. B.B. IGNITION	-	-	-	-	-	-	GAS	18,780	-	19,310.0	73,133	-	3.89
21. B.B.C.T.#4 TOTAL	**56**	**120**	**0.3**	**98.2**	**71.4**	**12,917**	**GAS**	**1,500**	**1,033,333**	**1,550.0**	**5,841**	**4.87**	**3.89**
22. BIG BEND STATION TOTAL	**1,533**	**98,410**	**8.9**	**76.1**	**40.7**	**12,438**	**-**	**-**	**-**	**1,223,990.0**	**4,360,934**	**4.43**	**-**
23. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
24. POLK #1 CT (GAS)	210	58,060	38.4	-	85.6	8,377	GAS	473,140	1,028,004	486,390.0	1,842,511	3.17	3.89
25. POLK #1 TOTAL	**220**	**58,060**	**36.7**	**92.5**	**85.6**	**8,377**	**-**	**-**	**-**	**486,390.0**	**1,842,511**	**3.17**	**-**
26. POLK #2 ST DUCT FIRING	120	15,980	18.5	-	80.2	8,274	GAS	128,620	1,027,989	132,220.0	500,874	3.13	3.89
27. POLK #2 ST W/O DUCT FIRING	341	553,334	-	-	-	-	GAS	3,814,592	1,028,010	3,921,437.1	14,854,855	2.68	3.89
28. POLK #2 ST TOTAL	**461**	**569,314**	**171.5**	**-**	**141.0**	**7,120**	**GAS**	**-**	**-**	**4,053,657.1**	**15,355,729**	**2.70**	**-**
29. POLK #2 CT (GAS)	150	500	0.5	-	83.3	12,200	GAS	5,940	1,026,936	6,100.0	23,132	4.63	3.89
30. POLK #2 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,754	23.91	127.49
31. POLK #2 TOTAL [4]	**150**	**1,143**	**1.1**	**-**	**89.2**	**11,524**	**-**	**-**	**-**	**13,171.4**	**176,886**	**15.48**	**-**
32. POLK #3 CT (GAS)	150	490	0.5	-	81.7	12,204	GAS	5,820	1,027,491	5,980.0	22,664	4.63	3.89
33. POLK #3 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,753	23.91	127.49
34. POLK #3 TOTAL [4]	**150**	**1,133**	**1.0**	**-**	**88.4**	**11,519**	**-**	**-**	**-**	**13,051.4**	**176,417**	**15.57**	**-**
35. POLK #4 CT (GAS) TOTAL [4]	**150**	**300**	**0.3**	**-**	**100.0**	**11,733**	**GAS**	**3,420**	**1,029,240**	**3,520.0**	**13,318**	**4.44**	**3.89**
36. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #2 CC TOTAL	**1,061**	**571,890**	**74.9**	**98.2**	**139.9**	**7,140**	**-**	**-**	**-**	**4,083,399.9**	**15,722,350**	**2.75**	**-**
38. POLK STATION TOTAL	**1,281**	**629,950**	**68.3**	**97.2**	**125.5**	**7,254**	**-**	**-**	**-**	**4,569,789.9**	**17,564,861**	**2.79**	**-**
39. BAYSIDE #1	701	434,370	86.1	97.2	88.5	7,288	GAS	3,079,670	1,028,000	3,165,900.0	11,992,908	2.76	3.89
40. BAYSIDE #2	929	526,240	78.7	97.5	81.7	7,367	GAS	3,771,240	1,027,999	3,876,830.0	14,686,033	2.79	3.89
41. BAYSIDE #3	56	1,460	3.6	98.6	89.9	11,849	GAS	16,830	1,027,926	17,300.0	65,540	4.49	3.89
42. BAYSIDE #4	56	540	1.3	98.6	80.4	12,759	GAS	6,700	1,028,358	6,890.0	26,091	4.83	3.89
43. BAYSIDE #5	56	2,870	7.1	98.6	88.4	11,798	GAS	32,930	1,028,242	33,860.0	128,237	4.47	3.89
44. BAYSIDE #6	56	2,220	5.5	98.6	88.1	11,730	GAS	25,340	1,027,624	26,040.0	98,679	4.45	3.89
45. BAYSIDE STATION TOTAL	**1,854**	**967,700**	**72.5**	**97.5**	**84.7**	**7,365**	**GAS**	**6,932,710**	**1,027,999**	**7,126,820.0**	**26,997,488**	**2.79**	**3.89**
46. SYSTEM TOTAL	**5,104**	**1,764,260**	**48.0**	**82.7**	**102.6**	**7,324**	**-**	**-**	**-**	**12,920,599.9**	**48,923,283**	**2.77**	**-**

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: OCTOBER 2019

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,670	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	200	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	12,330	24.1	-	24.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	12,800	23.6	-	23.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	11,900	21.9	-	21.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	9,110	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	9,330	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	7,180	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	7,280	20.0	-	20.0	-	SOLAR	-	-	-	-	-	-
11. SOLAR TOTAL [3]	**436.2**	**74,050**	**22.8**	**-**	**22.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
12. BIG BEND #1 TOTAL	**305**	**0**	**0.0**	**91.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
13. BIG BEND #2 TOTAL	**340**	**13,100**	**5.2**	**91.9**	**38.1**	**12,158**	**GAS**	**154,940**	**1,027,946**	**159,270.0**	**615,984**	**4.70**	**3.98**
14. B.B.#3 (GAS)	345	25,350	9.9	-	-	-	GAS	278,770	1,028,016	286,580.0	1,108,286	4.37	3.98
15. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
16. BIG BEND #3 TOTAL	**395**	**25,350**	**8.6**	**89.5**	**49.4**	**11,305**		**-**	**-**	**286,580.0**	**1,108,286**	**4.37**	**-**
17. B.B.#4 (GAS)	185	860	0.6	-	-	-	GAS	10,190	1,027,478	10,470.0	40,512	4.71	3.98
18. B.B.#4 (COAL)	437	16,380	5.0	-	-	-	COAL	8,840	22,504,525	198,940.0	674,636	4.12	76.32
19. BIG BEND #4 TOTAL	**437**	**17,240**	**5.3**	**9.8**	**45.9**	**12,147**		**-**	**-**	**209,410.0**	**715,148**	**4.15**	**-**
20. B.B. IGNITION	-	-	-	-	-	-	GAS	27,550	-	28,320.0	109,529	-	3.98
21. B.B.C.T.#4 TOTAL	**56**	**190**	**0.5**	**76.0**	**84.8**	**12,579**	**GAS**	**2,320**	**1,030,172**	**2,390.0**	**9,223**	**4.85**	**3.98**
22. BIG BEND STATION TOTAL	**1,533**	**55,880**	**4.9**	**67.3**	**45.2**	**11,769**	**-**	**-**	**-**	**657,650.0**	**2,558,170**	**4.58**	**-**
23. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
24. POLK #1 CT (GAS)	210	26,810	17.2	-	89.9	8,251	GAS	215,180	1,028,023	221,210.0	855,476	3.19	3.98
25. POLK #1 TOTAL	**220**	**26,810**	**16.4**	**50.7**	**89.9**	**8,251**	**-**	**-**	**-**	**221,210.0**	**855,476**	**3.19**	**-**
26. POLK #2 ST DUCT FIRING	120	14,610	16.4	-	73.3	8,276	GAS	117,610	1,028,059	120,910.0	467,574	3.20	3.98
27. POLK #2 ST W/O DUCT FIRING	341	537,696	-	-	-	-	GAS	3,699,062	1,028,010	3,802,672.9	14,706,104	2.74	3.98
28. POLK #2 ST TOTAL	**461**	**552,306**	**161.0**	**-**	**134.0**	**7,104**	**GAS**	**-**	**-**	**3,923,582.9**	**15,173,678**	**2.75**	**-**
29. POLK #2 CT (GAS)	150	1,020	0.9	-	97.1	11,588	GAS	11,500	1,027,826	11,820.0	45,719	4.48	3.98
30. POLK #2 CT (OIL)	159	600	0.5	-	94.3	11,000	LGT OIL	1,126	5,861,456	6,600.0	143,542	23.92	127.48
31. POLK #2 TOTAL [4]	**150**	**1,620**	**1.5**	**-**	**96.1**	**11,370**	**-**	**-**	**-**	**18,420.0**	**189,261**	**11.68**	**-**
32. POLK #3 CT (GAS)	150	900	0.8	-	100.0	11,500	GAS	10,070	1,027,805	10,350.0	40,035	4.45	3.98
33. POLK #3 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,840	23.92	127.48
34. POLK #3 TOTAL [4]	**150**	**1,564**	**1.4**	**-**	**97.5**	**11,290**	**-**	**-**	**-**	**17,657.1**	**198,875**	**12.72**	**-**
35. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
36. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #2 CC TOTAL	**1,061**	**555,490**	**70.4**	**95.8**	**133.1**	**7,128**	**-**	**-**	**-**	**3,959,660.0**	**15,561,814**	**2.80**	**-**
38. POLK STATION TOTAL	**1,281**	**582,300**	**61.1**	**88.0**	**127.3**	**7,180**	**-**	**-**	**-**	**4,180,870.0**	**16,417,290**	**2.82**	**-**
39. BAYSIDE #1	701	374,850	71.9	84.6	84.9	7,303	GAS	2,662,980	1,028,002	2,737,550.0	10,587,024	2.82	3.98
40. BAYSIDE #2	929	488,640	70.7	97.5	73.4	7,415	GAS	3,524,420	1,028,002	3,623,110.0	14,011,791	2.87	3.98
41. BAYSIDE #3	56	1,080	2.6	98.6	96.4	11,519	GAS	12,120	1,026,403	12,440.0	48,185	4.46	3.98
42. BAYSIDE #4	56	580	1.4	98.6	94.2	11,638	GAS	6,580	1,025,836	6,750.0	26,160	4.51	3.98
43. BAYSIDE #5	56	1,910	4.6	98.6	97.4	11,445	GAS	21,290	1,026,773	21,860.0	84,641	4.43	3.98
44. BAYSIDE #6	56	1,380	3.3	98.6	98.6	11,406	GAS	15,320	1,027,415	15,740.0	60,907	4.41	3.98
45. BAYSIDE STATION TOTAL	**1,854**	**868,440**	**63.0**	**92.8**	**78.0**	**7,390**	**GAS**	**6,242,710**	**1,027,991**	**6,417,450.0**	**24,818,708**	**2.86**	**3.98**
46. SYSTEM TOTAL	**5,104**	**1,580,670**	**41.6**	**76.0**	**102.7**	**7,121**	**-**	**-**	**-**	**11,255,970.0**	**43,794,168**	**2.77**	**-**

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: NOVEMBER 2019

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	230	22.8	-	22.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,030	21.9	-	21.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	170	16.9	-	16.9	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	9,180	18.5	-	18.5	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	9,260	17.6	-	17.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	10,460	19.9	-	19.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	7,370	17.1	-	17.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	7,100	18.1	-	18.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	6,090	23.2	-	23.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	6,350	18.0	-	18.0	-	SOLAR	-	-	-	-	-	-
11. SOLAR TOTAL [3]	**436.2**	**59,240**	**18.9**	**-**	**18.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
12. BIG BEND #1 TOTAL	**305**	**19,110**	**8.7**	**42.9**	**60.8**	**11,999**	**GAS**	**223,050**	**1,028,021**	**229,300.0**	**890,002**	**4.66**	**3.99**
13. BIG BEND #2 TOTAL	**340**	**9,750**	**4.0**	**42.9**	**53.1**	**11,235**	**GAS**	**106,550**	**1,028,062**	**109,540.0**	**425,150**	**4.36**	**3.99**
14. B.B.#3 (GAS)	345	49,570	20.0	-	-	-	GAS	533,950	1,027,999	548,900.0	2,130,539	4.30	3.99
15. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
16. BIG BEND #3 TOTAL	**395**	**49,570**	**17.4**	**89.5**	**54.8**	**11,073**		**-**	**-**	**548,900.0**	**2,130,539**	**4.30**	**-**
17. B.B.#4 (GAS)	185	5,880	4.4	-	-	-	GAS	71,610	1,028,069	73,620.0	285,734	4.86	3.99
18. B.B.#4 (COAL)	437	111,700	35.5	-	-	-	COAL	62,170	22,499,115	1,398,770.0	4,678,032	4.19	75.25
19. BIG BEND #4 TOTAL	**437**	**117,580**	**37.4**	**75.6**	**41.8**	**12,522**		**-**	**-**	**1,472,390.0**	**4,963,766**	**4.22**	**-**
20. B.B. IGNITION	-	-	-	-	-	-	GAS	25,460	-	26,180.0	101,589	-	3.99
21. B.B.C.T.#4 TOTAL	**56**	**1,520**	**3.8**	**78.6**	**93.6**	**11,559**	**GAS**	**17,100**	**1,027,485**	**17,570.0**	**68,232**	**4.49**	**3.99**
22. BIG BEND STATION TOTAL	**1,533**	**197,530**	**17.9**	**65.5**	**46.7**	**12,037**	**-**	**-**	**-**	**2,377,700.0**	**8,579,279**	**4.34**	**-**
23. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
24. POLK #1 CT (GAS)	210	56,790	37.6	-	89.3	8,286	GAS	457,780	1,027,961	470,580.0	1,826,610	3.22	3.99
25. POLK #1 TOTAL	**220**	**56,790**	**35.9**	**92.5**	**89.3**	**8,286**	**-**	**-**	**-**	**470,580.0**	**1,826,610**	**3.22**	**-**
26. POLK #2 ST DUCT FIRING	120	11,770	13.6	-	67.2	8,276	GAS	94,770	1,027,857	97,410.0	378,146	3.21	3.99
27. POLK #2 ST W/O DUCT FIRING	341	387,440	-	-	-	-	GAS	2,652,802	1,028,011	2,727,110.0	10,585,073	2.73	3.99
28. POLK #2 ST TOTAL	**461**	**399,210**	**120.3**	**-**	**118.1**	**7,075**	**GAS**	**-**	**-**	**2,824,520.0**	**10,963,219**	**2.75**	**-**
29. POLK #2 CT (GAS)	150	2,740	2.5	-	96.1	11,759	GAS	31,340	1,028,079	32,220.0	125,051	4.56	3.99
30. POLK #2 CT (OIL)	159	557	0.5	-	94.3	11,003	LGT OIL	1,045	5,864,689	6,128.6	133,214	23.92	127.48
31. POLK #2 TOTAL [4]	**150**	**3,297**	**3.1**	**-**	**95.8**	**11,631**	**-**	**-**	**-**	**38,348.6**	**258,265**	**7.83**	**-**
32. POLK #3 CT (GAS)	150	1,870	1.7	-	95.9	11,668	GAS	21,230	1,027,791	21,820.0	84,711	4.53	3.99
33. POLK #3 CT (OIL)	159	493	0.4	-	94.4	10,997	LGT OIL	925	5,860,973	5,421.4	117,917	23.92	127.48
34. POLK #3 TOTAL [4]	**150**	**2,363**	**2.2**	**-**	**95.6**	**11,528**	**-**	**-**	**-**	**27,241.4**	**202,628**	**8.58**	**-**
35. POLK #4 CT (GAS) TOTAL [4]	**150**	**810**	**0.8**	**-**	**90.0**	**12,111**	**GAS**	**9,540**	**1,028,302**	**9,810.0**	**38,066**	**4.70**	**3.99**
36. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #2 CC TOTAL	**1,061**	**405,680**	**53.1**	**73.1**	**116.8**	**7,148**	**-**	**-**	**-**	**2,899,920.0**	**11,462,178**	**2.83**	**-**
38. POLK STATION TOTAL	**1,281**	**462,470**	**50.1**	**76.4**	**109.1**	**7,288**	**-**	**-**	**-**	**3,370,500.0**	**13,288,788**	**2.87**	**-**
39. BAYSIDE #1	701	284,950	56.5	97.2	80.2	7,328	GAS	2,031,240	1,027,993	2,088,100.0	8,104,948	2.84	3.99
40. BAYSIDE #2	929	412,760	61.7	97.5	66.5	7,473	GAS	3,000,570	1,028,001	3,084,590.0	11,972,718	2.90	3.99
41. BAYSIDE #3	56	930	2.3	98.6	92.3	11,763	GAS	10,650	1,027,230	10,940.0	42,495	4.57	3.99
42. BAYSIDE #4	56	700	1.7	98.6	89.3	11,986	GAS	8,150	1,029,448	8,390.0	32,520	4.65	3.99
43. BAYSIDE #5	56	1,830	4.5	98.6	93.4	11,650	GAS	20,750	1,027,470	21,320.0	82,796	4.52	3.99
44. BAYSIDE #6	56	1,450	3.6	98.6	92.5	11,593	GAS	16,350	1,028,135	16,810.0	65,239	4.50	3.99
45. BAYSIDE STATION TOTAL	**1,854**	**702,620**	**52.6**	**97.5**	**71.6**	**7,444**	**GAS**	**5,087,710**	**1,027,997**	**5,230,150.0**	**20,300,716**	**2.89**	**3.99**
46. SYSTEM TOTAL	**5,104**	**1,421,860**	**38.7**	**74.3**	**83.9**	**7,721**	**-**	**-**	**-**	**10,978,350.0**	**42,168,783**	**2.97**	**-**

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: DECEMBER 2019

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	220	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	2,750	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	150	14.4	-	14.4	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	8,130	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	8,420	15.5	-	15.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	9,650	17.8	-	17.8	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	6,480	14.6	-	14.6	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	6,340	15.7	-	15.7	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	5,110	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	5,440	15.0	-	15.0	-	SOLAR	-	-	-	-	-	-
11. SOLAR TOTAL [3]	**436.2**	**52,690**	**16.2**	**-**	**16.2**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
12. BIG BEND #1 TOTAL	**315**	**0**	**0.0**	**91.9**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
13. BIG BEND #2 TOTAL	**350**	**21,650**	**8.3**	**91.9**	**40.4**	**11,740**	**GAS**	**247,260**	**1,027,987**	**254,180.0**	**1,016,063**	**4.69**	**4.11**
14. B.B.#3 (GAS)	355	27,990	10.6	-	-	-	GAS	305,340	1,028,034	313,900.0	1,254,730	4.48	4.11
15. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
16. BIG BEND #3 TOTAL	**400**	**27,990**	**9.4**	**89.5**	**48.3**	**11,215**		**-**	**-**	**313,900.0**	**1,254,730**	**4.48**	**-**
17. B.B.#4 (GAS)	195	5,930	4.1	-	-	-	GAS	72,130	1,028,005	74,150.0	296,403	5.00	4.11
18. B.B.#4 (COAL)	442	112,670	34.3	-	-	-	COAL	62,620	22,499,521	1,408,920.0	4,760,784	4.23	76.03
19. BIG BEND #4 TOTAL	**442**	**118,600**	**36.1**	**75.6**	**40.3**	**12,505**		**-**	**-**	**1,483,070.0**	**5,057,187**	**4.26**	**-**
20. B.B. IGNITION	-	-	-	-	-	-	GAS	20,450	-	21,030.0	84,035	-	4.11
21. B.B.C.T.#4 TOTAL	**61**	**50**	**0.1**	**98.2**	**82.0**	**11,600**	**GAS**	**570**	**1,017,544**	**580.0**	**2,342**	**4.68**	**4.11**
22. BIG BEND STATION TOTAL	**1,568**	**168,290**	**14.4**	**87.0**	**41.5**	**12,192**	**-**	**-**	**-**	**2,051,730.0**	**7,414,357**	**4.41**	**-**
23. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
24. POLK #1 CT (GAS)	230	50,760	29.7	-	86.5	8,310	GAS	410,320	1,028,027	421,820.0	1,686,123	3.32	4.11
25. POLK #1 TOTAL	**230**	**50,760**	**29.7**	**92.5**	**86.5**	**8,310**	**-**	**-**	**-**	**421,820.0**	**1,686,123**	**3.32**	**-**
26. POLK #2 ST DUCT FIRING	120	18,870	21.1	-	94.2	8,175	GAS	150,050	1,028,057	154,260.0	616,599	3.27	4.11
27. POLK #2 ST W/O DUCT FIRING	360	515,371	-	-	-	-	GAS	3,631,452	1,028,012	3,733,175.7	14,922,684	2.90	4.11
28. POLK #2 ST TOTAL	**480**	**534,241**	**149.6**	**-**	**123.5**	**7,277**	**GAS**	**-**	**-**	**3,887,435.7**	**15,539,283**	**2.91**	**-**
29. POLK #2 CT (GAS)	180	360	0.3	-	100.0	11,111	GAS	3,900	1,025,641	4,000.0	16,027	4.45	4.11
30. POLK #2 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
31. POLK #2 TOTAL [4]	**180**	**1,024**	**0.8**	**-**	**86.2**	**11,042**	**-**	**-**	**-**	**11,307.1**	**174,906**	**17.08**	**-**
32. POLK #3 CT (GAS)	180	350	0.3	-	97.2	11,200	GAS	3,810	1,028,871	3,920.0	15,656	4.47	4.11
33. POLK #3 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
34. POLK #3 TOTAL [4]	**180**	**1,014**	**0.8**	**-**	**85.3**	**11,072**	**-**	**-**	**-**	**11,227.1**	**174,534**	**17.21**	**-**
35. POLK #4 CT (GAS) TOTAL [4]	**180**	**340**	**0.3**	**-**	**94.4**	**11,500**	**GAS**	**3,800**	**1,028,947**	**3,910.0**	**15,615**	**4.59**	**4.11**
36. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
37. POLK #2 CC TOTAL	**1,200**	**536,619**	**60.1**	**97.2**	**122.9**	**7,294**	**-**	**-**	**-**	**3,913,879.9**	**15,904,338**	**2.96**	**-**
38. POLK STATION TOTAL	**1,430**	**587,379**	**55.2**	**96.5**	**115.0**	**7,381**	**-**	**-**	**-**	**4,335,699.9**	**17,590,461**	**2.99**	**-**
39. BAYSIDE #1	792	477,100	81.0	97.2	83.7	7,197	GAS	3,340,180	1,027,995	3,433,690.0	13,725,763	2.88	4.11
40. BAYSIDE #2	1,047	235,750	30.3	59.8	57.9	7,457	GAS	1,710,190	1,028,003	1,758,080.0	7,027,665	2.98	4.11
41. BAYSIDE #3	61	1,010	2.2	98.6	87.1	11,891	GAS	11,680	1,028,253	12,010.0	47,996	4.75	4.11
42. BAYSIDE #4	61	290	0.6	98.6	95.1	11,310	GAS	3,190	1,028,213	3,280.0	13,109	4.52	4.11
43. BAYSIDE #5	61	1,640	3.6	98.6	89.6	11,640	GAS	18,570	1,028,002	19,090.0	76,309	4.65	4.11
44. BAYSIDE #6	61	1,320	2.9	98.6	90.2	11,667	GAS	14,980	1,028,037	15,400.0	61,557	4.66	4.11
45. BAYSIDE STATION TOTAL	**2,083**	**717,110**	**46.3**	**78.5**	**73.0**	**7,309**	**GAS**	**5,098,790**	**1,027,999**	**5,241,550.0**	**20,952,399**	**2.92**	**4.11**
46. SYSTEM TOTAL	**5,517**	**1,525,469**	**37.2**	**79.4**	**88.0**	**7,623**	**-**	**-**	**-**	**11,628,979.9**	**45,957,217**	**3.01**	**-**

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 **SCHEDULE E5**
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD: JANUARY 2019 THROUGH JUNE 2019

	ACTUAL					
	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
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	0	0	0
16. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
17. AMOUNT ($)	0	0	0	0	0	0
18. BURNED:						
19. UNITS (BBL)	0	0	0	0	133	95
20. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	128.05	126.68
21. AMOUNT ($)	0	0	0	0	17,030	12,035
22. ENDING INVENTORY:						
23. UNITS (BBL)	43,998	43,998	43,998	43,998	43,865	43,770
24. UNIT COST ($/BBL)	127.48	127.48	127.48	127.48	127.48	127.48
25. AMOUNT ($)	5,609,055	5,609,055	5,609,055	5,609,055	5,592,025	5,579,990
26. DAYS SUPPLY: NORMAL	6	6	6	6	6	6
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	35,243	43,537	42,471	23,148	101,004	34,185
30. UNIT COST ($/TON)	63.66	66.82	70.93	65.66	69.47	87.09
31. AMOUNT ($)	2,243,622	2,909,338	3,012,483	1,519,856	7,017,109	2,977,136
32. BURNED:						
33. UNITS (TONS)	97,492	41,500	(683)	36,085	65,724	68,443
34. UNIT COST ($/TON)	72.08	76.76	(1,119.69)	84.79	76.95	77.09
35. AMOUNT ($)	7,027,027	3,185,512	764,747	3,059,647	5,057,428	5,276,546
36. ENDING INVENTORY:						
37. UNITS (TONS)	290,556	292,593	335,747	322,810	358,090	323,832
38. UNIT COST ($/TON)	71.65	71.82	71.06	70.99	70.83	72.66
39. AMOUNT ($)	20,818,864	21,013,952	23,859,040	22,915,539	25,363,274	23,530,493
40. DAYS SUPPLY:	104	139	195	176	166	151
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	9,444,940	9,261,927	10,652,608	11,615,296	13,471,550	12,152,315
43. UNIT COST ($/MCF)	4.34	3.43	3.40	3.24	3.41	3.51
44. AMOUNT ($)	40,956,715	31,750,210	36,253,362	37,610,162	45,902,802	42,623,195
45. BURNED:						
46. UNITS (MCF)	9,320,260	9,434,950	10,695,636	11,545,290	13,438,626	11,971,401
47. UNIT COST ($/MCF)	4.57	3.75	3.68	3.50	3.40	3.52
48. AMOUNT ($)	42,579,316	35,411,957	39,411,549	40,417,422	45,725,828	42,117,999
49. ENDING INVENTORY:						
50. UNITS (MCF)	555,614	382,591	339,563	409,569	442,493	623,407
51. UNIT COST ($/MCF)	3.77	3.63	3.55	3.26	3.18	2.94
52. AMOUNT ($)	2,095,268	1,389,915	1,206,906	1,334,686	1,408,176	1,835,849
53. DAYS SUPPLY:	2	1	1	1	1	2
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 **SCHEDULE E5**
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2019 THROUGH DECEMBER 2019

	Estimated						
	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	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)	0	0	0	0	0	0	0
16. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17. AMOUNT ($)	0	0	0	0	0	0	0
18. BURNED:							
19. UNITS (BBL)	2,492	2,492	2,412	2,372	1,970	2,492	14,458
20. UNIT COST ($/BBL)	127.51	127.51	127.49	127.48	127.48	127.51	127.50
21. AMOUNT ($)	317,757	317,757	307,507	302,382	251,131	317,757	1,843,356
22. ENDING INVENTORY:							
23. UNITS (BBL)	41,278	38,785	36,373	34,001	32,031	29,539	29,539
24. UNIT COST ($/BBL)	127.48	127.48	127.48	127.48	127.48	127.48	127.48
25. AMOUNT ($)	5,262,233	4,944,476	4,636,969	4,334,587	4,083,456	3,765,699	3,765,699
26. DAYS SUPPLY: NORMAL	6	6	5	5	5	4	-
27. DAYS SUPPLY: EMERGENCY	6	6	5	5	5	4	
COAL							
28. PURCHASES:							
29. UNITS (TONS)	98,201	60,129	60,129	60,129	59,321	44,247	661,744
30. UNIT COST ($/TON)	68.59	65.08	65.08	65.08	68.68	67.73	68.34
31. AMOUNT ($)	6,736,090	3,913,270	3,913,270	3,913,270	4,074,040	2,996,723	45,226,207
32. BURNED:							
33. UNITS (TONS)	61,590	62,320	30,360	8,840	62,170	62,620	596,461
34. UNIT COST ($/TON)	75.63	75.31	73.74	76.32	75.25	76.03	77.25
35. AMOUNT ($)	4,658,228	4,693,519	2,238,624	674,636	4,678,032	4,760,784	46,074,730
36. ENDING INVENTORY:							
37. UNITS (TONS)	372,727	370,536	400,305	451,594	448,745	430,372	430,372
38. UNIT COST ($/TON)	71.41	70.96	70.31	69.66	69.77	69.84	69.84
39. AMOUNT ($)	26,617,179	26,291,817	28,143,525	31,456,917	31,310,812	30,055,943	30,055,943
40. DAYS SUPPLY:	222	336	359	311	221	304	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	11,777,250	12,437,362	11,909,232	10,769,902	9,235,615	9,947,872	132,675,869
43. UNIT COST ($/MCF)	3.92	3.92	3.89	3.98	4.00	4.11	3.75
44. AMOUNT ($)	46,172,667	48,803,181	46,371,552	42,822,750	36,963,120	40,917,676	497,147,392
45. BURNED:							
46. UNITS (MCF)	12,011,552	12,437,362	11,909,232	10,769,902	9,332,892	9,947,872	132,814,975
47. UNIT COST ($/MCF)	3.90	3.92	3.89	3.98	3.99	4.11	3.83
48. AMOUNT ($)	46,854,916	48,799,181	46,377,152	42,817,150	37,239,620	40,878,676	508,630,766
49. ENDING INVENTORY:							
50. UNITS (MCF)	389,105	389,105	389,105	389,105	291,829	291,829	291,829
51. UNIT COST ($/MCF)	2.96	2.98	2.96	2.98	3.02	3.15	3.15
52. AMOUNT ($)	1,153,600	1,157,600	1,152,000	1,157,600	881,100	920,100	920,100
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 2019 THROUGH JUNE 2019

SCHEDULE E6

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH		CENTS/KWH				
			TYPE	TOTAL	WHEELED FROM	MWH	(A)	(B)	TOTAL $		GAINS ON
MONTH	SOLD TO		& SCHEDULE	MWH SOLD	OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST	MARKET BASED SALES
ACTUAL											
Jan-19	SEMINOLE	JURISD.	SCH. - D	2,838.2	1.2	2,837.0	2.267	2.493	64,301.51	70,731.66	2,905.74
	VARIOUS	JURISD.	SCH. - MA	3,109.0	0.0	3,109.0	2.314	3.524	71,957.73	109,548.05	30,781.97
	TOTAL			**5,947.2**	**1.2**	**5,946.0**	**2.292**	**3.032**	**136,259.24**	**180,279.71**	**33,687.71**
ACTUAL											
Feb-19	SEMINOLE	JURISD.	SCH. - D	3,148.0	0.0	3,148.0	2.200	2.420	69,268.28	76,195.11	3,633.78
	VARIOUS	JURISD.	SCH. - MA	1,584.0	0.0	1,584.0	2.191	3.187	34,708.77	50,477.88	12,277.47
	TOTAL			**4,732.0**	**0.0**	**4,732.0**	**2.197**	**2.677**	**103,977.05**	**126,672.99**	**15,911.25**
ACTUAL											
Mar-19	SEMINOLE	JURISD.	SCH. - D	3,279.0	0.0	3,279.0	2.026	2.229	66,433.89	73,077.28	3,212.76
	VARIOUS	JURISD.	SCH. - MA	1,259.0	0.0	1,259.0	2.299	3.443	28,943.67	43,345.01	13,037.99
	TOTAL			**4,538.0**	**0.0**	**4,538.0**	**2.102**	**2.565**	**95,377.56**	**116,422.29**	**16,250.75**
ACTUAL											
Apr-19	SEMINOLE	JURISD.	SCH. - D	3,315.0	0.0	3,315.0	1.836	2.019	60,852.52	66,937.77	3,631.07
	VARIOUS	JURISD.	SCH. - MA	1,699.0	0.0	1,699.0	2.224	3.975	37,788.77	67,538.23	27,731.05
	TOTAL			**5,014.0**	**0.0**	**5,014.0**	**1.967**	**2.682**	**98,641.29**	**134,476.00**	**31,362.12**
ACTUAL											
May-19	SEMINOLE	JURISD.	SCH. - D	2,232.0	0.0	2,232.0	1.971	2.168	43,994.38	48,393.82	2,203.76
	VARIOUS	JURISD.	SCH. - MA	12,516.0	0.0	12,516.0	2.568	4.276	321,377.08	535,239.94	194,939.61
	TOTAL			**14,748.0**	**0.0**	**14,748.0**	**2.477**	**3.957**	**365,371.46**	**583,633.76**	**197,143.37**
ACTUAL											
Jun-19	SEMINOLE	JURISD.	SCH. - D	1,716.0	0.0	1,716.0	1.743	1.918	29,913.42	32,904.76	2,187.61
	VARIOUS	JURISD.	SCH. - MA	8,763.0	0.0	8,763.0	2.819	4.719	247,026.20	413,519.83	158,620.01
	TOTAL			**10,479.0**	**0.0**	**10,479.0**	**2.643**	**4.260**	**276,939.62**	**446,424.59**	**160,807.62**

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2019 THROUGH DECEMBER 2019

SCHEDULE E6

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH		CENTS/KWH				
			TYPE	TOTAL	WHEELED FROM	MWH	(A)	(B)	TOTAL $		GAINS ON
MONTH	SOLD TO		& SCHEDULE	MWH SOLD	OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST	MARKET BASED SALES
ESTIMATED											
Jul-19	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	2.634	2.779	15,280.00	16,117.64	837.64
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**580.0**	**0.0**	**580.0**	**2.634**	**2.779**	**15,280.00**	**16,117.64**	**837.64**
ESTIMATED											
Aug-19	SEMINOLE	JURISD.	SCH. - D	570.0	0.0	570.0	2.733	2.888	15,580.00	16,459.09	879.09
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**570.0**	**0.0**	**570.0**	**2.733**	**2.888**	**15,580.00**	**16,459.09**	**879.09**
ESTIMATED											
Sep-19	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	2.848	3.011	16,520.00	17,463.03	943.03
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**580.0**	**0.0**	**580.0**	**2.848**	**3.011**	**16,520.00**	**17,463.03**	**943.03**
ESTIMATED											
Oct-19	SEMINOLE	JURISD.	SCH. - D	570.0	0.0	570.0	2.914	3.085	16,610.00	17,582.31	972.31
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**570.0**	**0.0**	**570.0**	**2.914**	**3.085**	**16,610.00**	**17,582.31**	**972.31**
ESTIMATED											
Nov-19	SEMINOLE	JURISD.	SCH. - D	570.0	0.0	570.0	2.988	3.162	17,030.00	18,023.68	993.68
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**570.0**	**0.0**	**570.0**	**2.988**	**3.162**	**17,030.00**	**18,023.68**	**993.68**
ESTIMATED											
Dec-19	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	3.031	3.212	17,580.00	18,629.95	1,049.95
	VARIOUS	JURISD.	SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL			**580.0**	**0.0**	**580.0**	**3.031**	**3.212**	**17,580.00**	**18,629.95**	**1,049.95**
TOTAL											
Jan-19	SEMINOLE	JURISD.	SCH. - D	19,978.2	1.2	19,977.0	2.169	2.365	433,364.00	472,516.10	23,450.42
THRU	VARIOUS	JURISD.	SCH. - MA	28,930.0	0.0	28,930.0	2.564	4.216	741,802.22	1,219,668.94	437,388.10
Dec-19	**TOTAL**			**48,908.2**	**1.2**	**48,907.0**	**2.403**	**3.460**	**1,175,166.22**	**1,692,185.04**	**460,838.52**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL									
Jan-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	(2.31)
	VARIOUS	EMERG A	224.0	0.0	0.0	224.0	13.405	13.405	30,027.04
	VARIOUS	OATT	227.0	0.0	0.0	227.0	2.236	2.236	5,075.86
	TOTAL		**451.0**	**0.0**	**0.0**	**451.0**	**7.783**	**7.783**	**35,100.59**
ACTUAL									
Feb-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	103,802.04
	VARIOUS	EMERG A	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	489.0	0.0	0.0	489.0	2.048	2.048	10,014.10
	TOTAL		**489.0**	**0.0**	**0.0**	**489.0**	**23.275**	**23.275**	**113,816.14**
ACTUAL									
Mar-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	329.0	0.0	0.0	329.0	2.356	2.356	7,751.62
	TOTAL		**329.0**	**0.0**	**0.0**	**329.0**	**2.356**	**2.356**	**7,751.62**
ACTUAL									
Apr-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	627.0	0.0	0.0	627.0	3.104	3.104	19,463.32
	TOTAL		**627.0**	**0.0**	**0.0**	**627.0**	**3.104**	**3.104**	**19,463.32**
ACTUAL									
May-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	1,226.0	0.0	0.0	1,226.0	2.184	2.184	26,772.26
	TOTAL		**1,226.0**	**0.0**	**0.0**	**1,226.0**	**2.184**	**2.184**	**26,772.26**
ACTUAL									
Jun-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	765.0	0.0	0.0	765.0	1.512	1.512	11,566.96
	TOTAL		**765.0**	**0.0**	**0.0**	**765.0**	**1.512**	**1.512**	**11,566.96**
ESTIMATED									
Jul-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	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-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	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-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	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-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	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-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	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-19	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	EMERG A	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	PASCO COGEN	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	103,799.73
Jan-19	VARIOUS	EMERG A	224.0	0.0	0.0	224.0	13.405	13.405	30,027.04
THRU	VARIOUS	OATT	3,663.0	0.0	0.0	3,663.0	2.202	2.202	80,644.12
Dec-19	**TOTAL**		**3,887.0**	**0.0**	**0.0**	**3,887.0**	**5.518**	**5.518**	**214,470.89**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL	VARIOUS	CO-GEN.							
Jan-19		NET METERING	2.3	0.0	0.0	2.3	2.331	2.331	53.61
		AS AVAIL.	23,727.0	0.0	0.0	23,727.0	2.618	2.618	621,105.41
	TOTAL		23,729.3	0.0	0.0	23,729.3	2.618	2.618	621,159.02
ACTUAL	VARIOUS	CO-GEN.							
Feb-19		NET METERING	1,506.9	0.0	0.0	1,506.9	2.529	2.529	38,113.28
		AS AVAIL.	12,803.0	0.0	0.0	12,803.0	2.419	2.419	309,675.82
	TOTAL		14,309.9	0.0	0.0	14,309.9	2.430	2.430	347,789.10
ACTUAL	VARIOUS	CO-GEN.							
Mar-19		NET METERING	3.7	0.0	0.0	3.7	2.496	2.496	92.35
		AS AVAIL.	11,829.0	0.0	0.0	11,829.0	2.244	2.244	265,433.72
	TOTAL		11,832.7	0.0	0.0	11,832.7	2.244	2.244	265,526.07
ACTUAL	VARIOUS	CO-GEN.							
Apr-19		NET METERING	102.5	0.0	0.0	102.5	2.531	2.531	2,593.77
		AS AVAIL.	18,573.0	0.0	0.0	18,573.0	2.008	2.008	372,962.50
	TOTAL		18,675.5	0.0	0.0	18,675.5	2.011	2.011	375,556.27
ACTUAL	VARIOUS	CO-GEN.							
May-19		NET METERING	1.2	0.0	0.0	1.2	2.545	2.545	30.54
		AS AVAIL.	18,177.0	0.0	0.0	18,177.0	2.094	2.094	380,715.18
	TOTAL		18,178.2	0.0	0.0	18,178.2	2.095	2.095	380,745.72
ACTUAL	VARIOUS	CO-GEN.							
Jun-19		NET METERING	6.9	0.0	0.0	6.9	2.522	2.522	174.01
		AS AVAIL.	14,569.0	0.0	0.0	14,569.0	1.939	1.939	282,438.42
	TOTAL		14,575.9	0.0	0.0	14,575.9	1.939	1.939	282,612.43
ESTIMATED	VARIOUS	CO-GEN.							
Jul-19		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	10,390.0	0.0	0.0	10,390.0	2.880	2.880	299,280.00
	TOTAL		10,390.0	0.0	0.0	10,390.0	2.880	2.880	299,280.00
ESTIMATED	VARIOUS	CO-GEN.							
Aug-19		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	10,390.0	0.0	0.0	10,390.0	2.862	2.862	297,310.00
	TOTAL		10,390.0	0.0	0.0	10,390.0	2.862	2.862	297,310.00
ESTIMATED	VARIOUS	CO-GEN.							
Sep-19		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	10,270.0	0.0	0.0	10,270.0	3.092	3.092	317,540.00
	TOTAL		10,270.0	0.0	0.0	10,270.0	3.092	3.092	317,540.00
ESTIMATED	VARIOUS	CO-GEN.							
Oct-19		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	10,460.0	0.0	0.0	10,460.0	2.865	2.865	299,630.00
	TOTAL		10,460.0	0.0	0.0	10,460.0	2.865	2.865	299,630.00
ESTIMATED	VARIOUS	CO-GEN.							
Nov-19		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	10,170.0	0.0	0.0	10,170.0	2.741	2.741	278,720.00
	TOTAL		10,170.0	0.0	0.0	10,170.0	2.741	2.741	278,720.00
ESTIMATED	VARIOUS	CO-GEN.							
Dec-19		NET METERING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		AS AVAIL.	10,450.0	0.0	0.0	10,450.0	2.956	2.956	308,860.00
	TOTAL		10,450.0	0.0	0.0	10,450.0	2.956	2.956	308,860.00
TOTAL	VARIOUS	CO-GEN.							
Jan-19		NET METERING	1,623.5	0.0	0.0	1,623.5	2.529	2.529	41,057.56
THRU		AS AVAIL.	161,808.0	0.0	0.0	161,808.0	2.493	2.493	4,033,671.05
Dec-19	TOTAL		163,431.5	0.0	0.0	163,431.5	2.493	2.493	4,074,728.61

TAMPA ELECTRIC COMPANY **SCHEDULE E9**
ECONOMY ENERGY PURCHASES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (9B)-(8)
ACTUAL	VARIOUS	SCH. - J	11,444.0	143.8	11,300.2	5.599	632,705.00	7.214	815,251.00	182,546.00
Jan-19	**TOTAL**		**11,444.0**	**143.8**	**11,300.2**	**5.599**	**632,705.00**	**7.214**	**815,251.00**	**182,546.00**
ACTUAL	VARIOUS	SCH. - J	7,753.0	0.0	7,753.0	3.273	253,770.99	3.528	273,510.94	19,739.95
Feb-19	**TOTAL**		**7,753.0**	**0.0**	**7,753.0**	**3.273**	**253,770.99**	**3.528**	**273,510.94**	**19,739.95**
ACTUAL	VARIOUS	SCH. - J	42,507.0	0.0	42,507.0	4.094	1,740,312.00	5.925	2,518,476.85	778,164.85
Mar-19	**TOTAL**		**42,507.0**	**0.0**	**42,507.0**	**4.094**	**1,740,312.00**	**5.925**	**2,518,476.85**	**778,164.85**
ACTUAL	VARIOUS	SCH. - J	44,979.0	0.0	44,979.0	5.553	2,497,767.00	6.113	2,749,779.00	252,012.00
Apr-19	**TOTAL**		**44,979.0**	**0.0**	**44,979.0**	**5.553**	**2,497,767.00**	**6.113**	**2,749,779.00**	**252,012.00**
ACTUAL	VARIOUS	SCH. - J	43,345.0	0.0	43,345.0	3.621	1,569,479.17	4.728	2,049,209.77	479,730.60
May-19	**TOTAL**		**43,345.0**	**0.0**	**43,345.0**	**3.621**	**1,569,479.17**	**4.728**	**2,049,209.77**	**479,730.60**
ACTUAL	VARIOUS	SCH. - J	215,886.0	0.0	215,886.0	3.678	7,939,932.11	3.866	8,346,647.79	406,715.68
Jun-19	**TOTAL**		**215,886.0**	**0.0**	**215,886.0**	**3.678**	**7,939,932.11**	**3.866**	**8,346,647.79**	**406,715.68**
ESTIMATED	VARIOUS	ECONOMY	180,910.0	0.0	180,910.0	3.539	6,403,130.00	4.858	8,788,273.12	2,385,143.12
Jul-19	**TOTAL**		**180,910.0**	**0.0**	**180,910.0**	**3.539**	**6,403,130.00**	**4.858**	**8,788,273.12**	**2,385,143.12**
ESTIMATED	VARIOUS	ECONOMY	180,780.0	0.0	180,780.0	3.536	6,391,970.00	4.338	7,841,987.81	1,450,017.81
Aug-19	**TOTAL**		**180,780.0**	**0.0**	**180,780.0**	**3.536**	**6,391,970.00**	**4.338**	**7,841,987.81**	**1,450,017.81**
ESTIMATED	VARIOUS	ECONOMY	176,300.0	0.0	176,300.0	3.534	6,229,950.00	4.763	8,397,328.41	2,167,378.41
Sep-19	**TOTAL**		**176,300.0**	**0.0**	**176,300.0**	**3.534**	**6,229,950.00**	**4.763**	**8,397,328.41**	**2,167,378.41**
ESTIMATED	VARIOUS	ECONOMY	181,440.0	0.0	181,440.0	3.530	6,404,170.00	4.406	7,994,886.05	1,590,716.05
Oct-19	**TOTAL**		**181,440.0**	**0.0**	**181,440.0**	**3.530**	**6,404,170.00**	**4.406**	**7,994,886.05**	**1,590,716.05**
ESTIMATED	VARIOUS	ECONOMY	10,860.0	0.0	10,860.0	4.066	441,550.00	11.966	1,299,560.00	858,010.00
Nov-19	**TOTAL**		**10,860.0**	**0.0**	**10,860.0**	**4.066**	**441,550.00**	**11.966**	**1,299,560.00**	**858,010.00**
ESTIMATED	VARIOUS	ECONOMY	1,720.0	0.0	1,720.0	4.806	82,660.00	83.159	1,430,330.00	1,347,670.00
Dec-19	**TOTAL**		**1,720.0**	**0.0**	**1,720.0**	**4.806**	**82,660.00**	**83.159**	**1,430,330.00**	**1,347,670.00**
TOTAL										
Jan-19	VARIOUS	SCH. - J	365,914.0	143.8	365,770.2	4.001	14,633,966.27	4.580	16,752,875.35	2,118,909.08
THRU	VARIOUS	ECONOMY	732,010.0	0.0	732,010.0	3.546	25,953,430.00	4.884	35,752,365.39	9,798,935.39
Dec-19	**TOTAL**		**1,097,924.0**	**143.8**	**1,097,780.2**	**3.697**	**40,587,396.27**	**4.783**	**52,505,240.74**	**11,917,844.47**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

CAPACITY COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2019 THROUGH DECEMBER 2019

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2019 THROUGH DECEMBER 2019

1.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2019 THROUGH DECEMBER 2019	1,422,896
2.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2018 THROUGH DECEMBER 2018 INCLUDED IN 2019	(5,458,886)
3.	PROJECTED UNDER-RECOVERY TRUE-UP INCLUDED IN APRIL - DECEMBER 2019 FACTORS (Per Mid-Course Petition, Exhibit D, Page 5 of 6, Line 8a)	1,160,527
4.	PROJECTED UNDER-RECOVERY TRUE-UP INCLUDED IN JANUARY - MARCH 2019 FACTORS (Per Mid-Course Petition, Exhibit D, Page 5 of 6, Line 8a)	696,246
5.	MID-COURSE TRUE-UP OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2019 THROUGH DECEMBER 2019 (SUM OF LINES 2 - 4)	(3,602,113)
6.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2020 THROUGH DECEMBER 2020 (LINE 1 + LINE 5)	(2,179,217)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2019 THROUGH DECEMBER 2019

	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	Total
1 UNIT POWER CAPACITY CHARGES	20,134	6,889	69,936	43,758	24,484	84,447	0	0	0	0	0	0	249,648
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3 (UNIT POWER CAPACITY REVENUES)	(75,831)	(86,888)	(75,240)	(78,649)	(130,227)	(118,353)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(1,130,376)
4 TOTAL CAPACITY DOLLARS	(55,697)	(79,999)	(5,304)	(34,891)	(105,743)	(33,906)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(880,728)
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	(55,697)	(79,999)	(5,304)	(34,891)	(105,743)	(33,906)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(880,728)
7 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	1,240,565	1,244,911	1,212,875	(85,626)	(102,382)	(164,985)	(160,691)	(160,457)	(166,966)	(152,146)	(127,384)	(121,629)	2,456,085
8 PRIOR PERIOD TRUE-UP PROVISION	(232,082)	(232,082)	(232,082)	(128,947)	(128,947)	(128,947)	(128,947)	(128,947)	(128,947)	(128,947)	(128,947)	(128,951)	(1,856,773)
9 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	1,008,483	1,012,829	980,793	(214,573)	(231,329)	(293,932)	(289,638)	(289,404)	(295,913)	(281,093)	(256,331)	(250,580)	599,312
10 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 9 - Line 6)	1,064,180	1,092,828	986,097	(179,682)	(125,586)	(260,026)	(195,440)	(195,206)	(201,715)	(186,895)	(162,133)	(156,382)	1,480,040
11 INTEREST PROVISION FOR MONTH	(9,670)	(7,055)	(4,581)	(3,416)	(3,404)	(3,451)	(3,931)	(4,427)	(4,355)	(4,237)	(4,338)	(4,279)	(57,144)
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	(5,458,886)	(4,172,294)	(2,854,439)	(1,640,841)	(1,694,992)	(1,695,035)	(1,829,565)	(1,899,989)	(1,970,675)	(2,047,798)	(2,109,983)	(2,147,507)	(5,458,886)
14 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	232,082	232,082	232,082	128,947	128,947	128,947	128,947	128,947	128,947	128,947	128,947	128,951	1,856,773
15 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 10 - 14)	**(4,172,294)**	**(2,854,439)**	**(1,640,841)**	**(1,694,992)**	**(1,695,035)**	**(1,829,565)**	**(1,899,989)**	**(1,970,675)**	**(2,047,798)**	**(2,109,983)**	**(2,147,507)**	**(2,179,217)**	**(2,179,217)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2019 THROUGH DECEMBER 2019

	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	Total
1 BEGINNING TRUE-UP AMOUNT	(5,458,886)	(4,172,294)	(2,854,439)	(1,640,841)	(1,694,992)	(1,695,035)	(1,829,565)	(1,899,989)	(1,970,675)	(2,047,798)	(2,109,983)	(2,147,507)	(5,458,886)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(4,162,624)	(2,847,384)	(1,636,260)	(1,691,576)	(1,691,631)	(1,826,114)	(1,896,058)	(1,966,248)	(2,043,443)	(2,105,746)	(2,143,169)	(2,174,938)	(2,122,073)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(9,621,510)	(7,019,678)	(4,490,699)	(3,332,417)	(3,386,623)	(3,521,149)	(3,725,623)	(3,866,237)	(4,014,118)	(4,153,544)	(4,253,152)	(4,322,445)	(7,580,959)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(4,810,755)	(3,509,839)	(2,245,350)	(1,666,209)	(1,693,312)	(1,760,575)	(1,862,812)	(1,933,119)	(2,007,059)	(2,076,772)	(2,126,576)	(2,161,223)	(3,790,480)
5 INTEREST RATE % - 1ST DAY OF MONTH	2.420	2.410	2.410	2.480	2.430	2.390	2.320	2.750	2.750	2.450	2.450	2.450	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	2.410	2.410	2.480	2.430	2.390	2.320	2.750	2.750	2.450	2.450	2.450	2.300	NA
7 TOTAL (LINE 5 + LINE 6)	4.830	4.820	4.890	4.910	4.820	4.710	5.070	5.500	5.200	4.900	4.900	4.750	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	2.415	2.410	2.445	2.455	2.410	2.355	2.535	2.750	2.600	2.450	2.450	2.375	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.201	0.201	0.204	0.205	0.201	0.196	0.211	0.229	0.217	0.204	0.204	0.198	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(9,670)	(7,055)	(4,581)	(3,416)	(3,404)	(3,451)	(3,931)	(4,427)	(4,355)	(4,237)	(4,338)	(4,279)	(57,144)

REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 201

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE	
SEMINOLE ELECTRIC **	6/1/1992		----------	LT

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT-TERM
** THREE YEAR NOTICE REQUIRED FOR TERMINATION.

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	8.1	10.8	9.1	9.3	11.5	18.4	2.0	2.0	2.0	2.0	2.0	2.0	
CAPACITY	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**	**($)**
FLORIDA POWER & LIGHT	[redacted]												
DUKE ENERGY FLORIDA													
JACKSONVILLE ELECTRIC AUTHORITY													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS - MA													
DUKE ENERGY FLORIDA - MA													
FLORIDA POWER & LIGHT - MA													
CITY OF LAKELAND - MA													
ORLANDO UTILITIES - MA													
EXGEN - MA													
REEDY CREEK - MA													
THE ENERGY AUTHORITY - MA													
MACQUARIE ENERGY LLC - MA													
MORGAN STANLEY - MA													
FMPA - MA													
NEW SMYRNA BEACH - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	**$ (55,697)**	**$ (79,999)**	**$ (5,304)**	**$ (34,891)**	**$ (105,743)**	**$ (33,906)**	**$ (94,198)**	**$ (94,198)**	**$ (94,198)**	**$ (94,198)**	**$ (94,198)**	**$ (94,198)**	**$ (880,728)**
TOTAL CAPACITY	**$ (55,697)**	**$ (79,999)**	**$ (5,304)**	**$ (34,891)**	**$ (105,743)**	**$ (33,906)**	**$ (94,198)**	**$ (94,198)**	**$ (94,198)**	**$ (94,198)**	**$ (94,198)**	**$ (94,198)**	**$ (880,728)**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2019 - DECEMBER 2019

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2019 THROUGH DECEMBER 2019

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$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	$20,910,348	$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	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9	DEPRECIATION EXPENSE	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$348,506	$4,182,070
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	$15,095,780	$15,444,286	$15,792,792	$16,141,297	$16,489,803	$16,838,309	$17,186,815	$17,535,321	$17,883,826	$18,232,332	$18,580,838	$18,929,344	$15,095,780
12	ENDING BALANCE DEPRECIATION	$15,444,286	$15,792,792	$16,141,297	$16,489,803	$16,838,309	$17,186,815	$17,535,321	$17,883,826	$18,232,332	$18,580,838	$18,929,344	$19,277,850	$19,277,850
13														
14														
15	ENDING NET INVESTMENT	$5,466,062	$5,117,557	$4,769,051	$4,420,545	$4,072,039	$3,723,533	$3,375,028	$3,026,522	$2,678,016	$2,329,510	$1,981,004	$1,632,499	$1,632,499
16														
17														
18	AVERAGE INVESTMENT	$5,640,315	$5,291,809	$4,943,304	$4,594,798	$4,246,292	$3,897,786	$3,549,280	$3,200,775	$2,852,269	$2,503,763	$2,155,257	$1,806,751	
19	ALLOWED EQUITY RETURN	.36019%	.36019%	.36019%	.36019%	.36019%	.36019%	.37413%	.37413%	.37413%	.37413%	.37413%	.37413%	
20	EQUITY COMPONENT AFTER-TAX	$20,316	$19,061	$17,805	$16,550	$15,295	$14,040	$13,279	$11,975	$10,671	$9,367	$8,064	$6,760	$163,183
21	CONVERSION TO PRE-TAX	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	
22	EQUITY COMPONENT PRE-TAX	$27,283	$25,598	$23,911	$22,226	$20,540	$18,855	$17,833	$16,082	$14,331	$12,579	$10,830	$9,078	$219,146
23														
24	ALLOWED DEBT RETURN	.14287%	.14287%	.14287%	.14287%	.14287%	.14287%	.14474%	.14474%	.14474%	.14474%	.14474%	.14474%	
25	DEBT COMPONENT	$8,058	$7,560	$7,062	$6,564	$6,067	$5,569	$5,137	$4,633	$4,128	$3,624	$3,120	$2,615	$64,137
26	TAX REFORM TRUEUP													
27	TOTAL RETURN REQUIREMENTS	$35,341	$33,158	$30,973	$28,790	$26,607	$24,424	$22,970	$20,715	$18,459	$16,203	$13,950	$11,693	$283,283
28	PRIOR MONTH TRUE-UP													
29	TOTAL DEPRECIATION & RETURN	$383,847	$381,664	$379,479	$377,296	$375,113	$372,930	$371,476	$369,221	$366,965	$364,709	$362,456	$360,199	$4,465,355
30														
31	ESTIMATED FUEL SAVINGS	$556,528	$515,586	$413,422	$695,832	$685,374	$495,625	$369,736	$830,879	$369,868	$552,355	$459,933	$365,559	$6,310,698
32	TOTAL DEPRECIATION & RETURN	$383,847	$381,664	$379,479	$377,296	$375,113	$372,930	$371,476	$369,221	$366,965	$364,709	$362,456	$360,199	$4,465,355
33	NET BENEFIT (COST) TO RATEPAYER	$172,681	$133,923	$33,943	$318,536	$310,261	$122,695	($1,740)	$461,658	$2,904	$187,647	$97,477	$5,360	$1,845,344

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - JUNE USING AN ANNUAL RATE OF 7.5190% (EQUITY 5.8046% , DEBT 1.7144%) RATES ARE BASED ON THE MAY 2018 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - DECEMBER USING AN ANNUAL RATE OF 7.7662% (EQUITY 6.0293% , DEBT 1.7369%) RATES ARE BASED ON THE MAY 2019 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 25.345%
38 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 2019 to June 2019

	(1) Jurisdictional Rate Base Actual May 2018 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,719,219	30.51%	5.13%	1.5652%
Short Term Debt	244,333	4.34%	2.18%	0.0945%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	96,005	1.70%	2.43%	0.0414%
Common Equity	2,367,502	42.02%	10.25%	4.3067%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,187,473	21.07%	0.00%	0.0000%
Deferred ITC - Weighted Cost	20,116	0.36%	8.10%	0.0289%
Total	$ 5,634,648	100.00%		6.04%

ITC split between Debt and Equity:

Long Term Debt	$ 1,719,219	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,367,502	Equity - Common	54.00%
Total	$ 4,086,721	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.0289% * 46.00%	0.0133%
Equity = 0.0289% * 54.00%	0.0156%
Weighted Cost	0.0289%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3067%
Deferred ITC - Weighted Cost	0.0156%
	4.3223%
Times Tax Multiplier	1.34295
Total Equity Component	5.8046%

Total Debt Cost Rate:

Long Term Debt	1.5652%
Short Term Debt	0.0945%
Customer Deposits	0.0414%
Deferred ITC - Weighted Cost	0.0133%
Total Debt Component	1.7144%
	7.5190%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012 and 2017 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 Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
July 2019 to December 2019

	(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	83,633	1.39%	7.98%	0.1110%
Total	$ 6,011,707	100.00%		6.23%

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	2,598,065	Equity - Common	54.00%
Total	$ 4,495,662	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	0.0599%
Weighted Cost	0.1110%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	0.0599%
	4.4896%
Times Tax Multiplier	1.34295
Total Equity Component	6.0293%

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	0.0511%
Total Debt Component	1.7369%
	7.7662%

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

PENELOPE A. RUSK

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2020 - DECEMBER 2020

AND

SCHEDULE E12

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 63
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-3

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2020 THROUGH DECEMBER 2020
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	54.99%	9,587,607	1,990	1.08045	1.05238	10,089,768	2,150	49.25%	56.99%	56.40%
GS, CS	62.24%	984,036	180	1.08045	1.05236	1,035,556	195	5.05%	5.17%	5.16%
GSD Optional	4.71%	508,686	77	1.07575	1.04878	533,502	83	2.60%	2.20%	2.23%
GSD, SBF	70.76%	7,637,641	1,155	1.07575	1.04878	8,010,233	1,243	39.09%	32.94%	33.41%
IS,SBI	79.71%	649,419	93	1.02851	1.01705	660,489	96	3.22%	2.54%	2.59%
LS1	333.63%	154,170	5	1.08045	1.05238	162,245	6	0.79%	0.16%	0.21%
TOTAL		19,521,559	3,501			20,491,793	3,773	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2019 projected calendar data.
(2) Projected MWH sales for the period January 2020 thru December 2020.
(3) Based on 12 months average CP at meter.
(4) Based on 2019 projected demand losses.
(5) Based on 2019 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 2020 THROUGH DECEMBER 2020
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	0	0	0	0	0	0	0	0	0	0	0	570,000	570,000
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(1,130,376)
4	TOTAL CAPACITY DOLLARS	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	$475,802	($560,376)
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	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	($94,198)	$475,802	($560,376)
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2019 - DEC. 2019													2,179,217
8	TOTAL													$1,618,841
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$1,620,007

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2020 THROUGH DECEMBER 2020
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	49.25%	56.99%	61,356	852,244	913,600	9,587,607	9,587,607				0.00010
GS, CS	5.05%	5.17%	6,291	77,314	83,605	984,036	984,036				0.00008
GSD, SBF											
Secondary						6,246,534	6,246,534			0.03	
Primary						1,382,339	1,368,516			0.03	
Transmission						8,768	8,593			0.03	
GSD, SBF - Standard	39.09%	32.94%	48,698	492,594	541,292	7,637,641	7,623,643	58.93%	17,722,132		
GSD - Optional	2.60%	2.20%	3,239	32,899	36,138						
Secondary						498,981	498,981				0.00007
Primary						9,705	9,608				0.00007
Transmission						0	0				0.00007
IS, SBI											
Primary						116,796	115,628			0.03	
Transmission						532,623	521,971			0.03	
Total IS, SBI	3.22%	2.54%	4,011	37,984	41,995	649,419	637,599	54.21%	1,611,184		
LS1	0.79%	0.16%	984	2,393	3,377	154,170	154,170				0.00002
TOTAL	100.00%	100.00%	124,579	1,495,428	1,620,007	19,521,559	19,495,644				0.00008

(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 2020 through December 2020.
(7) Projected kWh sales at secondary for the period January 2020 through December 2020.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2020 through December 2020.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
SEMINOLE ELECTRIC **	6/1/1992	--------	LT

QF = QUALIFYING FACILITY
LT = LONG TERM
ST = SHORT-TERM
** THREE YEAR NOTICE REQUIRED FOR TERMINATION.

CONTRACT	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	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
VARIOUS SUBTOTAL CAPACITY PURCHASES	[redacted]												
SEMINOLE ELECTRIC - D VARIOUS MARKET BASED SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	(94,198)	475,802	(560,376)
TOTAL CAPACITY	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**($94,198)**	**$475,802**	**($560,376)**

DOCKET NO. 20190001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 1, PAGE 4 OF 4

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2020 - DECEMBER 2020

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1 Cost Recovery Clause Calculation	(JAN. 2020 - DEC. 2020)
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	(")
10-21	Schedule E4 System Net Generation & Fuel Cost	(")
22-23	Schedule E5 Inventory Analysis	(")
24-25	Schedule E6 Power Sold	(")
26	Schedule E7 Purchased Power	(")
27	Schedule E8 Energy Payment to Qualifying Facilities	(")
28	Schedule E9 Economy Energy Purchases	(")
29	Schedule E10 Residential Bill Comparison	(")
30	Schedule H1 Generating System Comparative Data	(JAN. - DEC. 2017-2020)

TAMPA ELECTRIC COMPANY **SCHEDULE E1**
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	541,616,128	20,296,164	2.66856
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Big Bend Units 1-4 Igniters Conversion Project	1,657,489	20,296,164 (1)	0.00817
4b.	Adjustment	0	0	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**543,273,617**	**20,296,164**	**2.67673**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	78,030	1,900	4.10684
7.	Energy Cost of Economy Purchases (E9)	4,058,520	86,120	4.71263
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	3,680,810	123,930	2.97007
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**7,817,360**	**211,950**	**3.68830**
11.	**TOTAL AVAILABLE MWH (LINE 5 + LINE 10)**		**20,508,114**	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	196,640	6,910	2.84573
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	0	0	0.00000
14.	Gains on Sales	11,744	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**208,384**	**6,910**	**3.01569**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		307	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**550,882,593**	**20,500,897**	**2.68711**
20.	Net Unbilled	NA (1)(a)	NA (a)	NA
21.	Company Use	999,605 (1)	37,200	0.00513
22.	T & D Losses	25,881,416 (1)	963,169	0.13272
23.	System MWH Sales	550,882,593	19,500,528	2.82496
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	550,882,593	19,500,528	2.82496
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	550,882,593	19,500,528	2.82496
28.	Optimization Mechanism{2}	1,120,353	19,500,528	0.00575
29.	True-up (2)	30,742,026	19,500,528	0.15765
30.	Total Jurisdictional Fuel Cost (Excl. GPIF)	582,744,972	19,500,528	2.98835
31.	Revenue Tax Factor			1.00072
32.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	583,164,548	19,500,528	2.99050
33.	GPIF Adjusted for Taxes (2)	4,141,330	19,500,528	0.02124
34.	**Fuel Factor Adjusted for Taxes Including GPIF**	587,305,878	19,500,528	3.01174
35	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.012**

(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 2020 THROUGH DECEMBER 2020

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2019 - December 2019 (6 months actual, 6 months estimated)	($27,562,704)
2.	PROJECTED UNDER-RECOVERY TRUE-UP INCLUDED IN APRIL - DECEMBER 2019 RATES (Per Mid-Course correction Schedule E1-C, line 1B)	($35,545,462)
3.	DIFFERENCE IN 2018 ESTIMATED TRUE-UP AMOUNT PROJECTED IN ORIGINAL 2019 RATES AND AMOUNT COLLECTED IN 2019 ($7,015,485 over-recovery less $584,624 refunded each month January through March 2019)	$5,261,613
4.	ACTUAL-ESTIMATED 2019 OVER/(UNDER) RECOVERY TO BE COLLECTED IN 2020 (Line 1 - Line 2 + Line 3)	$13,244,371
5.	FINAL TRUE-UP (January 2018 - December 2018) (Per True-Up filed March 1, 2019)	(43,986,397)
6.	TOTAL OVER/(UNDER) RECOVERY (Line 4 + Line 5) To be included in the 12-month projected period January 2020 through December 202((Schedule E1, line 28)	($30,742,026)
7.	JURISDICTIONAL MWH SALES (Projected January 2020 through December 2020)	19,500,528
8.	TRUE-UP FACTOR - cents/kWh (Using Effective MWh Sales of 19,474,612)	**0.1579**

TAMPA ELECTRIC COMPANY **SCHEDULE E1-C**
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2020 through December 2020)	$4,141,330	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2020 through December 2020)	($30,742,026)	
	C. OPTIMIZATION MECHANISM GAIN / (LOSS) (January 2020 through December 2020)	$1,120,353	
2.	TOTAL SALES (January 2020 through December 2020)	19,500,528	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR (Using Effective MWh Sales of 19,474,612)	**0.0213**	Cents/kWh
	B. TRUE-UP FACTOR (Using Effective MWh Sales of 19,474,612)	**0.1579**	Cents/kWh
	C. OPTIMIZATION MECHANISM FACTOR (Using Effective MWh Sales of 19,474,612)	**0.0058**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E1-D

		NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK		29.95	$23.72
OFF PEAK		70.05	$22.15
		100.00	1.0709

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$550,882,593		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,500,528		
2a	Effective MWH Sales (Jurisd)		19,474,612		
3	Cost Per KWH Sold	(line 1 / line 2)	2.8250		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		NA		
6	True-Up	(Sch E1 line 29)	$30,742,026		
7	Optimization Mechanism	(Sch E1 line 28)	$1,120,353		
8	TOTAL	(line 1 x line 4) + line 6 + line 7	$582,744,972		
9	Revenue Tax Factor		1.00072		
10	Recovery Factor	(line 8 x line 9) / line 2a / 10	2.9945		
11	GPIF Factor	(Sch E1-C line 3A)	0.0213		
12	Recovery Factor Including GPIF	(line 10 + line 11)	3.0158	3.1624	2.9531
13	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.016	3.162	2.953

14	Hours: ON PEAK	25.39%
15	OFF PEAK	74.61%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Line Loss	Secondary
Distribution Secondary	17,450,297		17,450,297
Distribution Primary	1,508,840	0.99	1,493,752
Transmission	541,391	0.98	530,563
Total	19,500,528		19,474,612

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.016	3.162	2.953
Distribution Primary	2.986	3.130	2.923
Transmission	2.956	3.099	2.894
RS 1st Tier	2.702		
RS 2nd Tier	3.702		
Lighting	2.989		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

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)		2.702	3.702
Distribution Secondary	3.016		
Distribution Primary	2.986		
Transmission	2.956		
Lighting Service (1)	2.989		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.162		
Distribution Secondary - Off-Peak	2.953		
Distribution Primary - On-Peak	3.130		
Distribution Primary - Off-Peak	2.923		
Transmission - On-Peak	3.099		
Transmission - Off-Peak	2.894		

(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 2020 THROUGH DECEMBER 2020

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
						ESTIMATED							TOTAL
	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	PERIOD
1. Fuel Cost of System Net Generation	44,880,984	38,132,255	38,521,895	38,369,419	43,090,030	50,237,743	53,414,246	55,164,897	51,815,437	46,376,579	38,768,531	42,844,112	541,616,128
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold [1]	17,750	16,352	16,012	17,782	19,086	18,800	16,987	16,722	19,033	15,991	17,030	16,839	208,384
4. Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	78,030	78,030
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	282,290	274,130	286,020	293,010	306,640	300,450	327,220	332,740	290,490	341,270	353,060	293,490	3,680,810
7. Energy Cost of Economy Purchases	17,480	46,010	230,400	124,990	534,220	522,050	178,720	440,030	349,380	1,169,790	244,200	201,250	4,058,520
8. Big Bend Units 1-4 Igniters Conversion Project	357,944	355,688	353,433	351,177	239,247	0	0	0	0	0	0	0	1,657,489
9. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10. TOTAL FUEL & NET POWER TRANSACTIONS	**45,520,948**	**38,791,731**	**39,375,736**	**39,120,814**	**44,151,051**	**51,041,443**	**53,903,199**	**55,920,945**	**52,436,274**	**47,871,648**	**39,348,761**	**43,400,043**	**550,882,593**
11. Jurisdictional MWH Sold	1,500,869	1,346,196	1,325,733	1,421,475	1,564,939	1,823,864	1,909,750	1,931,881	1,952,467	1,795,872	1,500,089	1,427,393	19,500,528
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)	45,520,948	38,791,731	39,375,736	39,120,814	44,151,051	51,041,443	53,903,199	55,920,945	52,436,274	47,871,648	39,348,761	43,400,043	550,882,593
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)	**45,520,948**	**38,791,731**	**39,375,736**	**39,120,814**	**44,151,051**	**51,041,443**	**53,903,199**	**55,920,945**	**52,436,274**	**47,871,648**	**39,348,761**	**43,400,043**	**550,882,593**
16. Cost Per kWh Sold (Cents/kWh)	3.0330	2.8816	2.9701	2.7521	2.8213	2.7985	2.8225	2.8946	2.6856	2.6656	2.6231	3.0405	2.8250
17. Optimization Mechanism (Cents/kWh)[2]	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058	0.0058
18. True-up (Cents/kWh) [2]	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579	0.1579
19. Total (Cents/kWh) (Line 16+17+18)	3.1967	3.0453	3.1338	2.9158	2.9850	2.9622	2.9862	3.0583	2.8493	2.8293	2.7868	3.2042	2.9887
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)	3.1990	3.0475	3.1361	2.9179	2.9871	2.9643	2.9884	3.0605	2.8514	2.8313	2.7888	3.2065	2.9909
22. GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213	0.0213
23. TOTAL RECOVERY FACTOR (LINE 21+22)	**3.2203**	**3.0688**	**3.1574**	**2.9392**	**3.0084**	**2.9856**	**3.0097**	**3.0818**	**2.8727**	**2.8526**	**2.8101**	**3.2278**	**3.0122**
24. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**3.220**	**3.069**	**3.157**	**2.939**	**3.008**	**2.986**	**3.010**	**3.082**	**2.873**	**2.853**	**2.810**	**3.228**	**3.012**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

TAMPA ELECTRIC COMPANY **SCHEDULE E3**
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH JUNE 2020

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	317,757	297,257	317,757	240,881	297,257	307,507
3. COAL	4,796,166	274,531	0	824,594	142,161	2,135,479
4. NATURAL GAS	39,767,061	37,560,467	38,204,138	37,303,944	42,650,612	47,794,757
5. SOLAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**44,880,984**	**38,132,255**	**38,521,895**	**38,369,419**	**43,090,030**	**50,237,743**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	1,328	1,242	1,328	1,007	1,243	1,286
10. COAL	110,520	6,580	0	19,440	3,330	50,180
11. NATURAL GAS	1,319,091	1,209,907	1,308,921	1,388,433	1,619,817	1,759,724
12. SOLAR	87,260	99,820	122,030	147,960	161,380	138,420
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,518,199**	**1,317,549**	**1,432,279**	**1,556,840**	**1,785,770**	**1,949,610**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	2,492	2,332	2,492	1,890	2,331	2,412
17. COAL (TON)	62,380	3,830	0	10,610	1,840	28,040
18. NATURAL GAS (MCF)	9,335,262	8,907,432	9,459,532	10,268,582	11,926,772	13,351,492
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	14,614	13,671	14,614	11,079	13,671	14,143
23. COAL	1,403,530	86,270	0	238,710	41,410	630,980
24. NATURAL GAS	9,579,066	9,147,029	9,692,236	10,530,361	12,228,549	13,629,267
25. SOLAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**10,997,210**	**9,246,970**	**9,706,850**	**10,780,150**	**12,283,630**	**14,274,390**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.09	0.09	0.09	0.06	0.07	0.07
30. COAL	7.27	0.50	0.00	1.26	0.18	2.57
31. NATURAL GAS	86.89	91.83	91.39	89.18	90.71	90.26
32. SOLAR	5.75	7.58	8.52	9.50	9.04	7.10
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)	127.51	127.47	127.51	127.45	127.52	127.49
37. COAL ($/TON)	76.89	71.68	0.00	77.72	77.26	76.16
38. NATURAL GAS ($/MCF)	4.26	4.22	4.04	3.63	3.58	3.58
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 ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	21.74	21.74	21.74	21.74	21.74	21.74
43. COAL	3.42	3.18	0.00	3.45	3.43	3.38
44. NATURAL GAS	4.15	4.11	3.94	3.54	3.49	3.51
45. SOLAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.08**	**4.12**	**3.97**	**3.56**	**3.51**	**3.52**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	11,005	11,008	11,005	11,001	10,999	10,998
50. COAL	12,699	13,111	0	12,279	12,435	12,574
51. NATURAL GAS	7,262	7,560	7,405	7,584	7,549	7,745
52. SOLAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**7,244**	**7,018**	**6,777**	**6,924**	**6,879**	**7,322**
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	23.93	23.93	23.93	23.92	23.91	23.91
57. COAL	4.34	4.17	0.00	4.24	4.27	4.26
58. NATURAL GAS	3.01	3.10	2.92	2.69	2.63	2.72
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)	**2.96**	**2.89**	**2.69**	**2.46**	**2.41**	**2.58**

TAMPA ELECTRIC COMPANY **SCHEDULE E3**
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2020 THROUGH DECEMBER 2020

		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	317,757	317,757	307,507	179,379	225,505	317,757	3,444,078
3.	COAL	5,301,860	5,422,957	5,527,467	1,357,254	2,342,690	3,262,642	31,387,801
4.	NATURAL GAS	47,794,629	49,424,183	45,980,463	44,839,946	36,200,336	39,263,713	506,784,249
5.	SOLAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**53,414,246**	**55,164,897**	**51,815,437**	**46,376,579**	**38,768,531**	**42,844,112**	**541,616,128**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	1,328	1,328	1,286	750	943	1,328	14,397
10.	COAL	127,400	131,620	137,050	31,700	54,970	74,910	747,700
11.	NATURAL GAS	1,769,781	1,825,741	1,656,954	1,601,440	1,288,237	1,372,601	18,120,647
12.	SOLAR	135,120	130,800	112,660	112,340	89,200	76,430	1,413,420
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**2,033,629**	**2,089,489**	**1,907,950**	**1,746,230**	**1,433,350**	**1,525,269**	**20,296,164**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	2,492	2,492	2,412	1,407	1,769	2,492	27,013
17.	COAL (TON)	69,440	71,090	72,510	17,520	30,680	42,920	410,860
18.	NATURAL GAS (MCF)	13,150,682	13,636,082	12,579,822	12,163,571	9,657,212	10,059,302	134,495,743
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	14,614	14,614	14,143	8,250	10,371	14,614	158,399
23.	COAL	1,562,310	1,599,420	1,631,530	394,250	690,320	965,710	9,244,440
24.	NATURAL GAS	13,478,156	13,966,856	12,871,167	12,446,680	9,873,549	10,311,846	137,754,760
25.	SOLAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**15,055,080**	**15,580,890**	**14,516,840**	**12,849,180**	**10,574,240**	**11,292,170**	**147,157,599**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.07	0.06	0.07	0.04	0.07	0.09	0.07
30.	COAL	6.26	6.30	7.19	1.82	3.83	4.91	3.69
31.	NATURAL GAS	87.03	87.38	86.84	91.71	89.88	89.99	89.28
32.	SOLAR	6.64	6.26	5.90	6.43	6.22	5.01	6.96
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)	127.51	127.51	127.49	127.49	127.48	127.51	127.50
37.	COAL ($/TON)	76.35	76.28	76.23	77.47	76.36	76.02	76.40
38.	NATURAL GAS ($/MCF)	3.63	3.62	3.66	3.69	3.75	3.90	3.77
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 ($/MMBTU)								
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	21.74	21.74	21.74	21.74	21.74	21.74	21.74
43.	COAL	3.39	3.39	3.39	3.44	3.39	3.38	3.40
44.	NATURAL GAS	3.55	3.54	3.57	3.60	3.67	3.81	3.68
45.	SOLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**3.55**	**3.54**	**3.57**	**3.61**	**3.67**	**3.79**	**3.68**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	11,005	11,005	10,998	11,000	10,998	11,005	11,002
50.	COAL	12,263	12,152	11,905	12,437	12,558	12,892	12,364
51.	NATURAL GAS	7,616	7,650	7,768	7,772	7,664	7,513	7,602
52.	SOLAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**7,403**	**7,457**	**7,609**	**7,358**	**7,377**	**7,403**	**7,251**
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	23.93	23.93	23.91	23.92	23.91	23.93	23.92
57.	COAL	4.16	4.12	4.03	4.28	4.26	4.36	4.20
58.	NATURAL GAS	2.70	2.71	2.77	2.80	2.81	2.86	2.80
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)**	**2.63**	**2.64**	**2.72**	**2.66**	**2.70**	**2.81**	**2.67**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	220	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	2,920	20.4	-	20.4	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	170	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	9,860	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	10,220	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	12,320	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	8,190	18.4	-	18.4	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	7,510	18.6	-	18.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	5,470	20.1	-	20.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	6,520	17.9	-	17.9	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	11,540	20.7	-	20.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	12,320	22.2	-	22.2	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**87,260**	**20.0**	**-**	**20.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**315**	**6,230**	**2.7**	**91.8**	**38.0**	**13,526**	**GAS**	**81,970**	**1,028,059**	**84,270.0**	**349,182**	**5.60**	**4.26**
15. BIG BEND #2 TOTAL	**350**	**6,810**	**2.6**	**91.8**	**36.7**	**12,070**	**GAS**	**79,960**	**1,028,014**	**82,200.0**	**340,620**	**5.00**	**4.26**
16. B.B.#3 (GAS)	355	14,410	5.5	-	-	-	GAS	156,190	1,027,979	160,560.0	665,350	4.62	4.26
17. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**355**	**14,410**	**5.5**	**92.1**	**56.4**	**11,142**		**-**	**-**	**160,560.0**	**665,350**	**4.62**	**-**
19. B.B.#4 (GAS)	195	5,820	4.0	-	-	-	GAS	71,860	1,027,971	73,870.0	306,115	5.26	4.26
20. B.B.#4 (COAL)	442	110,520	33.6	-	-	-	COAL	62,380	22,499,679	1,403,530.0	4,796,166	4.34	76.89
21. BIG BEND #4 TOTAL	**442**	**116,340**	**35.4**	**86.2**	**38.4**	**12,699**		**-**	**-**	**1,477,400.0**	**5,102,281**	**4.39**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	17,120	-	17,600.0	72,929	-	4.26
23. B.B.C.T.#4 TOTAL	**61**	**160**	**0.4**	**98.2**	**87.4**	**11,375**	**GAS**	**1,770**	**-**	**1,820.0**	**7,540**	**4.71**	**4.26**
24. BIG BEND STATION TOTAL	**1,523**	**143,950**	**12.7**	**90.5**	**39.6**	**12,548**	**-**	**-**	**-**	**1,806,250.0**	**6,537,902**	**4.54**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	230	15,680	9.2	-	77.5	8,399	GAS	128,110	1,028,023	131,700.0	545,733	3.48	4.26
27. POLK #1 TOTAL	**230**	**15,680**	**9.2**	**87.4**	**77.5**	**8,399**	**-**	**-**	**-**	**131,700.0**	**545,733**	**3.48**	**-**
28. POLK #2 ST DUCT FIRING	120	3,650	4.1	-	78.0	8,164	GAS	28,990	1,027,941	29,800.0	123,494	3.38	4.26
29. POLK #2 ST W/O DUCT FIRING	360	685,581	-	-	-	-		4,615,322	1,028,010	4,744,595.7	19,660,700	2.87	4.26
30. POLK #2 ST TOTAL	**480**	**689,231**	**193.0**	**-**	**185.8**	**6,927**	**GAS**	**-**	**-**	**4,774,395.7**	**19,784,194**	**2.87**	**-**
31. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL [4]	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,879**	**23.93**	**-**
34. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL [4]	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,878**	**23.93**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,200**	**690,559**	**77.3**	**97.2**	**184.6**	**6,935**	**-**	**-**	**-**	**4,789,009.9**	**20,101,951**	**2.91**	**-**
40. POLK STATION TOTAL	**1,430**	**706,239**	**66.4**	**95.6**	**173.7**	**6,967**	**-**	**-**	**-**	**4,920,709.9**	**20,647,684**	**2.92**	**-**
41. BAYSIDE #1	792	416,470	70.7	97.2	72.7	7,238	GAS	2,932,460	1,028,000	3,014,570.0	12,491,917	3.00	4.26
42. BAYSIDE #2	1,047	163,620	21.0	96.8	45.2	7,626	GAS	1,213,820	1,027,986	1,247,790.0	5,170,722	3.16	4.26
43. BAYSIDE #3	61	190	0.4	98.6	77.9	12,000	GAS	2,220	1,027,027	2,280.0	9,457	4.98	4.26
44. BAYSIDE #4	61	170	0.4	98.6	69.7	12,412	GAS	2,050	1,029,268	2,110.0	8,733	5.14	4.26
45. BAYSIDE #5	61	50	0.1	98.6	82.0	10,600	GAS	520	1,019,231	530.0	2,215	4.43	4.26
46. BAYSIDE #6	61	250	0.6	98.6	82.0	11,880	GAS	2,900	1,024,138	2,970.0	12,354	4.94	4.26
47. BAYSIDE STATION TOTAL	**2,083**	**580,750**	**37.5**	**97.2**	**62.1**	**7,353**	**GAS**	**4,153,970**	**1,027,992**	**4,270,250.0**	**17,695,398**	**3.05**	**4.26**
48. SYSTEM TOTAL	**5,622**	**1,518,199**	**36.3**	**84.9**	**95.5**	**7,244**	**-**	**-**	**-**	**10,997,209.9**	**44,880,984**	**2.96**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	230	23.6	-	23.6	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,230	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	170	17.4	-	17.4	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	11,650	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	12,070	23.8	-	23.8	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	13,700	27.0	-	27.0	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	9,680	23.3	-	23.3	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	8,860	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	6,000	23.6	-	23.6	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	7,700	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	12,820	24.6	-	24.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	13,710	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**99,820**	**24.5**	**-**	**24.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**315**	**0**	**0.0**	**91.8**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
15. BIG BEND #2 TOTAL	**350**	**6,570**	**2.7**	**91.8**	**36.1**	**12,139**	**GAS**	**77,570**	**1,028,104**	**79,750.0**	**327,094**	**4.98**	**4.22**
16. B.B.#3 (GAS)	355	120,370	48.7	-	-	-	GAS	1,311,200	1,028,005	1,347,920.0	5,529,010	4.59	4.22
17. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**355**	**120,370**	**48.7**	**92.1**	**55.0**	**11,198**		**-**	**-**	**1,347,920.0**	**5,529,010**	**4.59**	**-**
19. B.B.#4 (GAS)	195	350	0.3	-	-	-	GAS	4,420	1,027,149	4,540.0	18,638	5.33	4.22
20. B.B.#4 (COAL)	442	6,580	2.1	-	-	-	COAL	3,830	22,524,804	86,270.0	274,531	4.17	71.68
21. BIG BEND #4 TOTAL	**442**	**6,930**	**2.3**	**8.9**	**34.8**	**13,104**		**-**	**-**	**90,810.0**	**293,169**	**4.23**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	9,600	-	9,880.0	40,481	-	4.22
23. B.B.C.T.#4 TOTAL	**61**	**40**	**0.1**	**98.2**	**65.6**	**13,500**	**GAS**	**530**	**1,018,868**	**540.0**	**2,235**	**5.59**	**4.22**
24. BIG BEND STATION TOTAL	**1,523**	**133,910**	**12.6**	**68.1**	**52.2**	**11,344**	**-**	**-**	**-**	**1,519,020.0**	**6,191,989**	**4.62**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	230	10,530	6.6	-	77.6	8,378	GAS	85,810	1,028,085	88,220.0	361,840	3.44	4.22
27. POLK #1 TOTAL	**230**	**10,530**	**6.6**	**67.6**	**77.6**	**8,378**	**-**	**-**	**-**	**88,220.0**	**361,840**	**3.44**	**-**
28. POLK #2 ST DUCT FIRING	120	5,660	6.8	-	72.6	8,177	GAS	45,030	1,027,759	46,280.0	189,881	3.35	4.22
29. POLK #2 ST W/O DUCT FIRING	360	629,797	-	-	-	-		4,239,942	1,028,009	4,358,698.6	17,878,800	2.84	4.22
30. POLK #2 ST TOTAL	**480**	**635,457**	**190.2**	**-**	**177.9**	**6,932**	**GAS**	**-**	**-**	**4,404,978.6**	**18,068,681**	**2.84**	**-**
31. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	187	621	0.5	-	80.2	11,008	LGT OIL	1,166	5,862,521	6,835.7	148,628	23.93	127.47
33. POLK #2 TOTAL [4]	**180**	**621**	**0.5**	**-**	**80.2**	**11,008**	**-**	**-**	**-**	**6,835.7**	**148,628**	**23.93**	**-**
34. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	187	621	0.5	-	80.2	11,008	LGT OIL	1,166	5,862,521	6,835.7	148,629	23.93	127.47
36. POLK #3 TOTAL [4]	**180**	**621**	**0.5**	**-**	**80.2**	**11,008**	**-**	**-**	**-**	**6,835.7**	**148,629**	**23.93**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,200**	**636,699**	**76.2**	**97.2**	**176.9**	**6,940**	**-**	**-**	**-**	**4,418,650.0**	**18,365,938**	**2.88**	**-**
40. POLK STATION TOTAL	**1,430**	**647,229**	**65.0**	**92.4**	**169.6**	**6,963**	**-**	**-**	**-**	**4,506,870.0**	**18,727,778**	**2.89**	**-**
41. BAYSIDE #1	792	327,030	59.3	93.9	66.5	7,278	GAS	2,315,450	1,027,999	2,380,280.0	9,763,688	2.99	4.22
42. BAYSIDE #2	1,047	109,180	15.0	56.7	43.1	7,658	GAS	813,290	1,028,010	836,070.0	3,429,446	3.14	4.22
43. BAYSIDE #3	61	50	0.1	98.6	82.0	12,600	GAS	610	1,032,787	630.0	2,572	5.14	4.22
44. BAYSIDE #4	61	50	0.1	98.6	82.0	12,600	GAS	610	1,032,787	630.0	2,572	5.14	4.22
45. BAYSIDE #5	61	230	0.5	98.6	75.4	12,348	GAS	2,760	1,028,986	2,840.0	11,638	5.06	4.22
46. BAYSIDE #6	61	50	0.1	98.6	82.0	12,600	GAS	610	1,032,787	630.0	2,572	5.14	4.22
47. BAYSIDE STATION TOTAL	**2,083**	**436,590**	**30.1**	**75.8**	**58.5**	**7,378**	**GAS**	**3,133,330**	**1,028,005**	**3,221,080.0**	**13,212,488**	**3.03**	**4.22**
48. SYSTEM TOTAL	**5,622**	**1,317,549**	**33.7**	**70.0**	**103.8**	**7,018**	**-**	**-**	**-**	**9,246,970.0**	**38,132,255**	**2.89**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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: MARCH 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	280	26.9	-	26.9	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,130	28.9	-	28.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	240	23.0	-	23.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	13,350	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	13,850	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	17,510	32.3	-	32.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	11,150	25.1	-	25.1	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	10,210	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,360	30.8	-	30.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	8,850	24.3	-	24.3	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	16,580	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	17,520	31.6	-	31.6	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**122,030**	**28.0**	**-**	**28.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**315**	**5,740**	**2.4**	**38.5**	**38.0**	**13,535**	**GAS**	**75,580**	**1,027,917**	**77,690.0**	**305,244**	**5.32**	**4.04**
15. BIG BEND #2 TOTAL	**350**	**19,340**	**7.4**	**91.8**	**38.4**	**11,932**	**GAS**	**224,470**	**1,028,022**	**230,760.0**	**906,565**	**4.69**	**4.04**
16. B.B.#3 (GAS)	355	41,100	15.6	-	-	-	GAS	450,090	1,027,994	462,690.0	1,817,775	4.42	4.04
17. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**355**	**41,100**	**15.6**	**92.1**	**53.6**	**11,258**		**-**	**-**	**462,690.0**	**1,817,775**	**4.42**	**-**
19. B.B.#4 (GAS)	195	0	0.0	-	-	-	GAS	0	0	0.0	0	0.00	0.00
20. B.B.#4 (COAL)	442	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
21. BIG BEND #4 TOTAL	**442**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	31,310	-	32,190.0	126,451	-	4.04
23. B.B.C.T.#4 TOTAL	**61**	**340**	**0.7**	**44.3**	**92.9**	**11,294**	**GAS**	**3,730**	**1,029,491**	**3,840.0**	**15,064**	**4.43**	**4.04**
24. BIG BEND STATION TOTAL	**1,523**	**66,520**	**5.9**	**52.3**	**46.8**	**11,650**	**-**	**-**	**-**	**774,980.0**	**3,171,100**	**4.77**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	230	23,380	13.7	-	80.7	8,381	GAS	190,590	1,028,071	195,940.0	769,734	3.29	4.04
27. POLK #1 TOTAL	**230**	**23,380**	**13.7**	**93.4**	**80.7**	**8,381**	**-**	**-**	**-**	**195,940.0**	**769,734**	**3.29**	**-**
28. POLK #2 ST DUCT FIRING	120	9,210	10.3	-	77.5	8,173	GAS	73,220	1,027,998	75,270.0	295,713	3.21	4.04
29. POLK #2 ST W/O DUCT FIRING	360	686,231	-	-	-	-		4,621,002	1,028,010	4,750,435.7	18,662,805	2.72	4.04
30. POLK #2 ST TOTAL	**480**	**695,441**	**194.7**	**-**	**174.6**	**6,939**	**GAS**	**-**	**-**	**4,825,705.7**	**18,958,518**	**2.73**	**-**
31. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL [4]	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,879**	**23.93**	**-**
34. POLK #3 CT (GAS)	180	140	0.1	-	77.8	11,500	GAS	1,570	1,025,478	1,610.0	6,341	4.53	4.04
35. POLK #3 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL [4]	**180**	**804**	**0.6**	**-**	**79.8**	**11,091**	**-**	**-**	**-**	**8,917.1**	**165,219**	**20.55**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,200**	**696,909**	**78.1**	**97.2**	**173.4**	**6,948**	**-**	**-**	**-**	**4,841,929.9**	**19,282,616**	**2.77**	**-**
40. POLK STATION TOTAL	**1,430**	**720,289**	**67.7**	**96.6**	**161.3**	**6,994**	**-**	**-**	**-**	**5,037,869.9**	**20,052,350**	**2.78**	**-**
41. BAYSIDE #1	792	246,790	41.9	62.7	68.6	7,264	GAS	1,743,880	1,027,995	1,792,700.0	7,042,995	2.85	4.04
42. BAYSIDE #2	1,047	272,720	35.0	96.8	51.4	7,543	GAS	2,001,000	1,027,996	2,057,020.0	8,081,423	2.96	4.04
43. BAYSIDE #3	61	880	1.9	79.5	96.2	11,352	GAS	9,720	1,027,778	9,990.0	39,256	4.46	4.04
44. BAYSIDE #4	61	580	1.3	79.5	95.1	11,345	GAS	6,410	1,026,521	6,580.0	25,888	4.46	4.04
45. BAYSIDE #5	61	1,350	3.0	95.4	96.2	11,200	GAS	14,710	1,027,872	15,120.0	59,409	4.40	4.04
46. BAYSIDE #6	61	1,120	2.5	98.6	96.6	11,241	GAS	12,250	1,027,755	12,590.0	49,474	4.42	4.04
47. BAYSIDE STATION TOTAL	**2,083**	**523,440**	**33.8**	**82.8**	**58.5**	**7,439**	**GAS**	**3,787,970**	**1,027,991**	**3,894,000.0**	**15,298,445**	**2.92**	**4.04**
48. SYSTEM TOTAL	**5,622**	**1,432,279**	**34.2**	**69.4**	**106.7**	**6,777**	**-**	**-**	**-**	**9,706,849.9**	**38,521,895**	**2.69**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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: APRIL 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	270	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,690	33.9	-	33.9	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	270	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	17,410	35.1	-	35.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	18,140	34.6	-	34.6	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	19,730	37.6	-	37.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	14,630	34.0	-	34.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	13,360	34.1	-	34.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	9,270	35.3	-	35.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	11,650	33.1	-	33.1	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	18,800	34.9	-	34.9	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	19,740	36.8	-	36.8	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**147,960**	**35.1**	**-**	**35.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**6,390**	**2.9**	**39.8**	**43.6**	**13,188**	**GAS**	**81,970**	**1,028,059**	**84,270.0**	**297,782**	**4.66**	**3.63**
15. BIG BEND #2 TOTAL	**340**	**15,610**	**6.4**	**36.7**	**43.3**	**11,734**	**GAS**	**178,180**	**1,027,949**	**183,160.0**	**647,296**	**4.15**	**3.63**
16. B.B.#3 (GAS)	345	40,330	16.2	-	-	-	GAS	436,800	1,027,999	449,030.0	1,586,817	3.93	3.63
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**40,330**	**16.2**	**92.1**	**60.6**	**11,134**		**-**	**-**	**449,030.0**	**1,586,817**	**3.93**	**-**
19. B.B.#4 (GAS)	185	1,020	0.8	-	-	-	GAS	12,220	1,027,823	12,560.0	44,393	4.35	3.63
20. B.B.#4 (COAL)	437	19,440	6.2	-	-	-	COAL	10,610	22,498,586	238,710.0	824,594	4.24	77.72
21. BIG BEND #4 TOTAL	**437**	**20,460**	**6.5**	**48.8**	**44.6**	**12,281**		**-**	**-**	**251,270.0**	**868,987**	**4.25**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	25,040	-	25,750.0	90,966	-	3.63
23. B.B.C.T.#4 TOTAL	**56**	**1,310**	**3.2**	**85.1**	**86.6**	**11,870**	**GAS**	**15,130**	**1,027,759**	**15,550.0**	**54,965**	**4.20**	**3.63**
24. BIG BEND STATION TOTAL	**1,483**	**84,100**	**7.9**	**55.6**	**51.5**	**11,692**	**-**	**-**	**-**	**983,280.0**	**3,546,814**	**4.22**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	58,880	38.9	-	84.2	8,364	GAS	479,080	1,028,012	492,500.0	1,740,413	2.96	3.63
27. POLK #1 TOTAL	**220**	**58,880**	**37.2**	**93.4**	**84.2**	**8,364**	**-**	**-**	**-**	**492,500.0**	**1,740,413**	**2.96**	**-**
28. POLK #2 ST DUCT FIRING	120	7,790	9.0	-	55.5	8,268	GAS	62,660	1,027,929	64,410.0	227,633	2.92	3.63
29. POLK #2 ST W/O DUCT FIRING	341	396,823	-	-	-	-		2,721,292	1,028,012	2,797,521.4	9,885,972	2.49	3.63
30. POLK #2 ST TOTAL	**461**	**404,613**	**121.9**	**-**	**124.8**	**7,073**	**GAS**	**-**	**-**	**2,861,931.4**	**10,113,605**	**2.50**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	493	0.4	-	94.4	10,997	LGT OIL	925	5,860,973	5,421.4	117,891	23.91	127.45
33. POLK #2 TOTAL [4]	**150**	**493**	**0.5**	**-**	**94.4**	**10,997**	**-**	**-**	**-**	**5,421.4**	**117,891**	**23.91**	**-**
34. POLK #3 CT (GAS)	150	4,940	4.6	-	94.1	11,719	GAS	56,320	1,027,876	57,890.0	204,601	4.14	3.63
35. POLK #3 CT (OIL)	159	514	0.4	-	94.3	11,006	LGT OIL	965	5,862,280	5,657.1	122,990	23.93	127.45
36. POLK #3 TOTAL [4]	**150**	**5,454**	**5.1**	**-**	**94.1**	**11,651**	**-**	**-**	**-**	**63,547.1**	**327,591**	**6.01**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**2,990**	**2.8**	**-**	**94.9**	**11,702**	**GAS**	**34,040**	**1,027,908**	**34,990.0**	**123,661**	**4.14**	**3.63**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**1,340**	**1.2**	**-**	**99.3**	**11,560**	**GAS**	**15,070**	**1,027,870**	**15,490.0**	**54,747**	**4.09**	**3.63**
39. POLK #2 CC TOTAL	**1,061**	**414,890**	**54.3**	**76.5**	**122.1**	**7,186**	**-**	**-**	**-**	**2,981,379.9**	**10,737,495**	**2.59**	**-**
40. POLK STATION TOTAL	**1,281**	**473,770**	**51.4**	**79.4**	**110.7**	**7,332**	**-**	**-**	**-**	**3,473,879.9**	**12,477,908**	**2.63**	**-**
41. BAYSIDE #1	701	408,440	80.9	97.2	83.1	7,313	GAS	2,905,490	1,027,999	2,986,840.0	10,555,132	2.58	3.63
42. BAYSIDE #2	929	435,400	65.1	96.8	66.9	7,471	GAS	3,164,090	1,027,999	3,252,680.0	11,494,579	2.64	3.63
43. BAYSIDE #3	56	1,880	4.7	98.6	93.3	11,686	GAS	21,380	1,027,596	21,970.0	77,670	4.13	3.63
44. BAYSIDE #4	56	1,360	3.4	98.6	97.1	11,537	GAS	15,260	1,028,178	15,690.0	55,437	4.08	3.63
45. BAYSIDE #5	56	2,170	5.4	82.2	92.3	11,631	GAS	24,550	1,028,106	25,240.0	89,186	4.11	3.63
46. BAYSIDE #6	56	1,760	4.4	78.9	92.4	11,688	GAS	20,010	1,027,986	20,570.0	72,693	4.13	3.63
47. BAYSIDE STATION TOTAL	**1,854**	**851,010**	**63.8**	**96.1**	**74.0**	**7,430**	**GAS**	**6,150,780**	**1,027,998**	**6,322,990.0**	**22,344,697**	**2.63**	**3.63**
48. SYSTEM TOTAL	**5,204**	**1,556,840**	**41.6**	**69.6**	**96.5**	**6,924**	**-**	**-**	**-**	**10,780,149.9**	**38,369,419**	**2.46**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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: MAY 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	290	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	5,060	35.4	-	35.4	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	290	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	19,560	38.2	-	38.2	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	20,360	37.5	-	37.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	20,540	37.9	-	37.9	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	16,380	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	14,940	36.9	-	36.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	10,090	37.2	-	37.2	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	13,020	35.8	-	35.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	20,290	36.5	-	36.5	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	20,560	37.1	-	37.1	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**161,380**	**37.0**	**-**	**37.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**18,090**	**8.0**	**91.8**	**54.4**	**12,362**	**GAS**	**217,530**	**1,027,996**	**223,620.0**	**777,896**	**4.30**	**3.58**
15. BIG BEND #2 TOTAL	**340**	**9,620**	**3.8**	**41.5**	**50.5**	**11,289**	**GAS**	**105,640**	**1,028,020**	**108,600.0**	**377,773**	**3.93**	**3.58**
16. B.B.#3 (GAS)	345	46,340	18.1	-	-	-	GAS	500,300	1,027,983	514,300.0	1,789,093	3.86	3.58
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**46,340**	**18.1**	**65.3**	**62.2**	**11,098**		**-**	**-**	**514,300.0**	**1,789,093**	**3.86**	**-**
19. B.B.#4 (GAS)	185	180	0.1	-	-	-	GAS	2,120	1,028,302	2,180.0	7,581	4.21	3.58
20. B.B.#4 (COAL)	437	3,330	1.0	-	-	-	COAL	1,840	22,505,435	41,410.0	142,161	4.27	77.26
21. BIG BEND #4 TOTAL	**437**	**3,510**	**1.1**	**86.2**	**42.3**	**12,419**		**-**	**-**	**43,590.0**	**149,742**	**4.27**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	31,310	-	32,190.0	111,966	-	3.58
23. B.B.C.T.#4 TOTAL	**56**	**990**	**2.4**	**98.2**	**88.4**	**11,778**	**GAS**	**11,340**	**1,028,219**	**11,660.0**	**40,552**	**4.10**	**3.58**
24. BIG BEND STATION TOTAL	**1,483**	**78,550**	**7.1**	**72.7**	**58.1**	**11,480**	**-**	**-**	**-**	**901,770.0**	**3,247,022**	**4.13**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	69,870	44.7	-	86.4	8,356	GAS	567,930	1,028,014	583,840.0	2,030,940	2.91	3.58
27. POLK #1 TOTAL	**220**	**69,870**	**42.7**	**93.4**	**86.4**	**8,356**	**-**	**-**	**-**	**583,840.0**	**2,030,940**	**2.91**	**-**
28. POLK #2 ST DUCT FIRING	120	21,010	23.5	-	73.9	8,272	GAS	169,070	1,027,977	173,800.0	604,601	2.88	3.58
29. POLK #2 ST W/O DUCT FIRING	341	527,257	-	-	-	-		3,625,582	1,028,011	3,727,138.6	12,965,226	2.46	3.58
30. POLK #2 ST TOTAL	**461**	**548,267**	**159.9**	**-**	**122.7**	**7,115**	**GAS**	**-**	**-**	**3,900,938.6**	**13,569,827**	**2.48**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,894	23.93	127.52
33. POLK #2 TOTAL [4]	**150**	**664**	**0.6**	**-**	**94.3**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,894**	**23.93**	**-**
34. POLK #3 CT (GAS)	150	120	0.1	-	80.0	13,167	GAS	1,540	1,025,974	1,580.0	5,507	4.59	3.58
35. POLK #3 CT (OIL)	159	579	0.5	-	94.4	10,992	LGT OIL	1,085	5,865,714	6,364.3	138,363	23.90	127.52
36. POLK #3 TOTAL [4]	**150**	**699**	**0.6**	**-**	**91.6**	**11,365**	**-**	**-**	**-**	**7,944.3**	**143,870**	**20.58**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**549,630**	**69.6**	**88.2**	**122.5**	**7,125**	**-**	**-**	**-**	**3,916,190.0**	**13,872,591**	**2.52**	**-**
40. POLK STATION TOTAL	**1,281**	**619,500**	**65.0**	**89.1**	**112.3**	**7,264**	**-**	**-**	**-**	**4,500,030.0**	**15,903,531**	**2.57**	**-**
41. BAYSIDE #1	701	431,760	82.8	97.2	85.1	7,305	GAS	3,068,010	1,028,002	3,153,920.0	10,971,326	2.54	3.58
42. BAYSIDE #2	929	482,530	69.8	96.8	71.6	7,437	GAS	3,490,900	1,027,996	3,588,630.0	12,483,597	2.59	3.58
43. BAYSIDE #3	56	2,690	6.5	98.6	94.2	11,584	GAS	30,320	1,027,704	31,160.0	108,426	4.03	3.58
44. BAYSIDE #4	56	1,580	3.8	98.6	94.0	11,576	GAS	17,790	1,028,106	18,290.0	63,618	4.03	3.58
45. BAYSIDE #5	56	4,480	10.8	98.6	94.1	11,545	GAS	50,320	1,027,822	51,720.0	179,946	4.02	3.58
46. BAYSIDE #6	56	3,300	7.9	98.6	93.5	11,548	GAS	37,070	1,028,055	38,110.0	132,564	4.02	3.58
47. BAYSIDE STATION TOTAL	**1,854**	**926,340**	**67.2**	**97.2**	**77.6**	**7,429**	**GAS**	**6,694,410**	**1,027,996**	**6,881,830.0**	**23,939,477**	**2.58**	**3.58**
48. SYSTEM TOTAL	**5,204**	**1,785,770**	**46.1**	**77.3**	**105.4**	**6,879**	**-**	**-**	**-**	**12,283,630.0**	**43,090,030**	**2.41**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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: JUNE 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	250	24.8	-	24.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,490	32.5	-	32.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	270	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	16,920	34.1	-	34.1	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	17,560	33.5	-	33.5	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	17,620	33.6	-	33.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	14,130	32.9	-	32.9	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	12,890	32.9	-	32.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,750	33.3	-	33.3	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	11,210	31.8	-	31.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	16,680	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	17,650	32.9	-	32.9	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**138,420**	**32.8**	**-**	**32.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**36,800**	**16.8**	**91.8**	**45.5**	**13,011**	**GAS**	**465,770**	**1,027,997**	**478,810.0**	**1,667,331**	**4.53**	**3.58**
15. BIG BEND #2 TOTAL	**340**	**52,400**	**21.4**	**91.8**	**49.7**	**11,372**	**GAS**	**579,630**	**1,028,018**	**595,870.0**	**2,074,920**	**3.96**	**3.58**
16. B.B.#3 (GAS)	345	58,990	23.7	-	-	-	GAS	635,610	1,027,989	653,400.0	2,275,313	3.86	3.58
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**58,990**	**23.7**	**76.7**	**62.4**	**11,076**		**-**	**-**	**653,400.0**	**2,275,313**	**3.86**	**-**
19. B.B.#4 (GAS)	185	2,640	2.0	-	-	-	GAS	32,300	1,028,173	33,210.0	115,625	4.38	3.58
20. B.B.#4 (COAL)	437	50,180	15.9	-	-	-	COAL	28,040	22,502,853	630,980.0	2,135,479	4.26	76.16
21. BIG BEND #4 TOTAL	**437**	**52,820**	**16.8**	**86.2**	**41.3**	**12,575**		**-**	**-**	**664,190.0**	**2,251,104**	**4.26**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	93,510	-	96,120.0	334,741	-	3.58
23. B.B.C.T.#4 TOTAL	**56**	**1,880**	**4.7**	**98.2**	**95.9**	**11,495**	**GAS**	**21,030**	**1,027,580**	**21,610.0**	**75,282**	**4.00**	**3.58**
24. BIG BEND STATION TOTAL	**1,483**	**202,890**	**19.0**	**86.9**	**49.6**	**11,897**	**-**	**-**	**-**	**2,413,880.0**	**8,678,691**	**4.28**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	81,100	53.6	-	87.8	8,321	GAS	656,430	1,028,015	674,820.0	2,349,843	2.90	3.58
27. POLK #1 TOTAL	**220**	**81,100**	**51.2**	**93.4**	**87.8**	**8,321**	**-**	**-**	**-**	**674,820.0**	**2,349,843**	**2.90**	**-**
28. POLK #2 ST DUCT FIRING	120	30,210	35.0	-	88.3	8,275	GAS	243,190	1,028,003	250,000.0	870,555	2.88	3.58
29. POLK #2 ST W/O DUCT FIRING	341	555,784	-	-	-	-		3,837,122	1,028,009	3,944,597.1	13,735,867	2.47	3.58
30. POLK #2 ST TOTAL	**461**	**585,994**	**176.5**	**-**	**127.8**	**7,158**	**GAS**	**-**	**-**	**4,194,597.1**	**14,606,422**	**2.49**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,754	23.91	127.49
33. POLK #2 TOTAL [4]	**150**	**643**	**0.6**	**-**	**94.4**	**10,998**	**-**	**-**	**-**	**7,071.4**	**153,754**	**23.91**	**-**
34. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,753	23.91	127.49
36. POLK #3 TOTAL [4]	**150**	**643**	**0.6**	**-**	**94.4**	**10,998**	**-**	**-**	**-**	**7,071.4**	**153,753**	**23.91**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**587,280**	**76.9**	**98.2**	**127.5**	**7,166**	**-**	**-**	**-**	**4,208,739.9**	**14,913,929**	**2.54**	**-**
40. POLK STATION TOTAL	**1,281**	**668,380**	**72.5**	**97.3**	**115.4**	**7,307**	**-**	**-**	**-**	**4,883,559.9**	**17,263,772**	**2.58**	**-**
41. BAYSIDE #1	701	425,680	84.3	97.2	87.0	7,297	GAS	3,021,730	1,028,001	3,106,340.0	10,816,982	2.54	3.58
42. BAYSIDE #2	929	498,760	74.6	96.8	76.6	7,406	GAS	3,593,010	1,028,002	3,693,620.0	12,862,011	2.58	3.58
43. BAYSIDE #3	56	3,420	8.5	98.6	96.9	11,468	GAS	38,160	1,027,778	39,220.0	136,603	3.99	3.58
44. BAYSIDE #4	56	2,640	6.5	98.6	98.2	11,375	GAS	29,200	1,028,425	30,030.0	104,528	3.96	3.58
45. BAYSIDE #5	56	5,160	12.8	98.6	97.0	11,434	GAS	57,390	1,028,054	59,000.0	205,441	3.98	3.58
46. BAYSIDE #6	56	4,260	10.6	98.6	96.3	11,441	GAS	47,410	1,028,053	48,740.0	169,715	3.98	3.58
47. BAYSIDE STATION TOTAL	**1,854**	**939,920**	**70.4**	**97.2**	**81.3**	**7,423**	**GAS**	**6,786,900**	**1,028,002**	**6,976,950.0**	**24,295,280**	**2.58**	**3.58**
48. SYSTEM TOTAL	**5,204**	**1,949,610**	**52.0**	**83.3**	**100.4**	**7,322**	**-**	**-**	**-**	**14,274,389.9**	**50,237,743**	**2.58**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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: JULY 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	240	23.0	-	23.0	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,340	30.4	-	30.4	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	260	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	16,400	32.0	-	32.0	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	17,010	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	17,410	32.1	-	32.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	13,690	30.8	-	30.8	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	12,500	30.9	-	30.9	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,520	31.4	-	31.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	10,850	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	16,450	29.6	-	29.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	17,450	31.5	-	31.5	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**135,120**	**31.0**	**-**	**31.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**6,110**	**2.7**	**91.8**	**41.7**	**13,365**	**GAS**	**79,440**	**1,027,946**	**81,660.0**	**288,715**	**4.73**	**3.63**
15. BIG BEND #2 TOTAL	**340**	**39,800**	**15.7**	**91.8**	**47.4**	**11,473**	**GAS**	**444,180**	**1,028,007**	**456,620.0**	**1,614,321**	**4.06**	**3.63**
16. B.B.#3 (GAS)	345	57,420	22.4	-	-	-	GAS	623,380	1,027,993	640,830.0	2,265,602	3.95	3.63
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**57,420**	**22.4**	**92.1**	**59.7**	**11,160**		**-**	**-**	**640,830.0**	**2,265,602**	**3.95**	**-**
19. B.B.#4 (GAS)	185	6,700	4.9	-	-	-	GAS	79,990	1,028,004	82,230.0	290,714	4.34	3.63
20. B.B.#4 (COAL)	437	127,400	39.2	-	-	-	COAL	69,440	22,498,704	1,562,310.0	5,301,860	4.16	76.35
21. BIG BEND #4 TOTAL	**437**	**134,100**	**41.2**	**86.2**	**44.8**	**12,264**		**-**	**-**	**1,644,540.0**	**5,592,574**	**4.17**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	39,660	-	40,770.0	144,140	-	3.63
23. B.B.C.T.#4 TOTAL	**56**	**1,260**	**3.0**	**98.2**	**83.3**	**12,167**	**GAS**	**14,920**	**1,027,480**	**15,330.0**	**54,225**	**4.30**	**3.63**
24. BIG BEND STATION TOTAL	**1,483**	**238,690**	**21.6**	**90.5**	**48.3**	**11,894**	**-**	**-**	**-**	**2,838,980.0**	**9,959,578**	**4.17**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	69,360	44.4	-	90.5	8,328	GAS	561,890	1,027,995	577,620.0	2,042,124	2.94	3.63
27. POLK #1 TOTAL	**220**	**69,360**	**42.4**	**93.4**	**90.5**	**8,328**	**-**	**-**	**-**	**577,620.0**	**2,042,124**	**2.94**	**-**
28. POLK #2 ST DUCT FIRING	120	30,810	34.5	-	90.4	8,276	GAS	248,050	1,027,978	254,990.0	901,509	2.93	3.63
29. POLK #2 ST W/O DUCT FIRING	341	579,401	-	-	-	-		4,002,322	1,028,010	4,114,425.7	14,545,975	2.51	3.63
30. POLK #2 ST TOTAL	**461**	**610,211**	**177.9**	**-**	**130.0**	**7,160**	**GAS**	**-**	**-**	**4,369,415.7**	**15,447,484**	**2.53**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL [4]	**150**	**664**	**0.6**	**-**	**94.3**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,879**	**23.93**	**-**
34. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL [4]	**150**	**664**	**0.6**	**-**	**94.3**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,878**	**23.93**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**611,539**	**77.5**	**98.1**	**129.7**	**7,169**	**-**	**-**	**-**	**4,384,029.9**	**15,765,241**	**2.58**	**-**
40. POLK STATION TOTAL	**1,281**	**680,899**	**71.4**	**97.3**	**119.4**	**7,287**	**-**	**-**	**-**	**4,961,649.9**	**17,807,365**	**2.62**	**-**
41. BAYSIDE #1	701	444,310	85.2	97.2	87.4	7,295	GAS	3,153,090	1,028,001	3,241,380.0	11,459,540	2.58	3.63
42. BAYSIDE #2	929	521,610	75.5	96.8	77.4	7,398	GAS	3,753,930	1,028,000	3,859,040.0	13,643,223	2.62	3.63
43. BAYSIDE #3	56	3,030	7.3	98.6	85.9	11,888	GAS	35,030	1,028,261	36,020.0	127,312	4.20	3.63
44. BAYSIDE #4	56	1,920	4.6	98.6	85.7	12,016	GAS	22,440	1,028,075	23,070.0	81,556	4.25	3.63
45. BAYSIDE #5	56	4,310	10.3	98.6	85.5	11,768	GAS	49,330	1,028,178	50,720.0	179,284	4.16	3.63
46. BAYSIDE #6	56	3,740	9.0	98.6	83.5	11,824	GAS	43,030	1,027,655	44,220.0	156,388	4.18	3.63
47. BAYSIDE STATION TOTAL	**1,854**	**978,920**	**71.0**	**97.2**	**81.8**	**7,411**	**GAS**	**7,056,850**	**1,028,001**	**7,254,450.0**	**25,647,303**	**2.62**	**3.63**
48. SYSTEM TOTAL	**5,204**	**2,033,629**	**52.5**	**84.4**	**98.8**	**7,403**	**-**	**-**	**-**	**15,055,079.9**	**53,414,246**	**2.63**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	4,250	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	15,830	30.9	-	30.9	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	16,410	30.3	-	30.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	16,830	31.0	-	31.0	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	13,220	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	12,080	29.8	-	29.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	8,380	30.9	-	30.9	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	10,470	28.8	-	28.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	15,940	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	16,890	30.5	-	30.5	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**130,800**	**30.0**	**-**	**30.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**21,240**	**9.4**	**91.8**	**52.4**	**12,485**	**GAS**	**257,960**	**1,028,028**	**265,190.0**	**934,980**	**4.40**	**3.62**
15. BIG BEND #2 TOTAL	**340**	**48,520**	**19.2**	**91.8**	**50.1**	**11,326**	**GAS**	**534,560**	**1,028,004**	**549,530.0**	**1,937,521**	**3.99**	**3.62**
16. B.B.#3 (GAS)	345	50,380	19.6	-	-	-	GAS	543,340	1,028,012	558,560.0	1,969,344	3.91	3.62
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**50,380**	**19.6**	**92.1**	**61.4**	**11,087**		**-**	**-**	**558,560.0**	**1,969,344**	**3.91**	**-**
19. B.B.#4 (GAS)	185	6,930	5.0	-	-	-	GAS	81,890	1,027,964	84,180.0	296,812	4.28	3.62
20. B.B.#4 (COAL)	437	131,620	40.5	-	-	-	COAL	71,090	22,498,523	1,599,420.0	5,422,957	4.12	76.28
21. BIG BEND #4 TOTAL	**437**	**138,550**	**42.6**	**86.2**	**46.3**	**12,152**		**-**	**-**	**1,683,600.0**	**5,719,769**	**4.13**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	49,680	-	51,070.0	180,066	-	3.62
23. B.B.C.T.#4 TOTAL	**56**	**1,900**	**4.6**	**98.2**	**91.7**	**11,584**	**GAS**	**21,410**	**1,028,024**	**22,010.0**	**77,601**	**4.08**	**3.62**
24. BIG BEND STATION TOTAL	**1,483**	**260,590**	**23.6**	**90.5**	**50.2**	**11,815**	**-**	**-**	**-**	**3,078,890.0**	**10,819,280**	**4.15**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	76,010	48.6	-	88.9	8,339	GAS	616,600	1,027,992	633,860.0	2,234,876	2.94	3.62
27. POLK #1 TOTAL	**220**	**76,010**	**46.4**	**93.4**	**88.9**	**8,339**	**-**	**-**	**-**	**633,860.0**	**2,234,876**	**2.94**	**-**
28. POLK #2 ST DUCT FIRING	120	30,420	34.1	-	88.6	8,275	GAS	244,870	1,027,974	251,720.0	887,535	2.92	3.62
29. POLK #2 ST W/O DUCT FIRING	341	577,821	-	-	-	-		3,989,402	1,028,010	4,101,145.7	14,459,647	2.50	3.62
30. POLK #2 ST TOTAL	**461**	**608,241**	**177.3**	**-**	**129.4**	**7,156**	**GAS**	**-**	**-**	**4,352,865.7**	**15,347,182**	**2.52**	**-**
31. POLK #2 CT (GAS)	150	1,050	0.9	-	100.0	11,486	GAS	11,730	1,028,133	12,060.0	42,515	4.05	3.62
32. POLK #2 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL [4]	**150**	**1,714**	**1.5**	**-**	**97.7**	**11,299**	**-**	**-**	**-**	**19,367.1**	**201,394**	**11.75**	**-**
34. POLK #3 CT (GAS)	150	1,050	0.9	-	100.0	11,486	GAS	11,730	1,028,133	12,060.0	42,516	4.05	3.62
35. POLK #3 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL [4]	**150**	**1,714**	**1.5**	**-**	**97.7**	**11,299**	**-**	**-**	**-**	**19,367.1**	**201,394**	**11.75**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**750**	**0.7**	**-**	**100.0**	**11,520**	**GAS**	**8,410**	**1,027,348**	**8,640.0**	**30,482**	**4.06**	**3.62**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**612,419**	**77.6**	**96.6**	**128.5**	**7,185**	**-**	**-**	**-**	**4,400,239.9**	**15,780,452**	**2.58**	**-**
40. POLK STATION TOTAL	**1,281**	**688,429**	**72.2**	**96.0**	**117.4**	**7,312**	**-**	**-**	**-**	**5,034,099.9**	**18,015,328**	**2.62**	**-**
41. BAYSIDE #1	701	450,090	86.3	97.2	88.6	7,291	GAS	3,192,080	1,028,001	3,281,460.0	11,569,742	2.57	3.62
42. BAYSIDE #2	929	545,740	79.0	96.8	81.3	7,376	GAS	3,915,520	1,028,001	4,025,160.0	14,191,860	2.60	3.62
43. BAYSIDE #3	56	2,990	7.2	98.6	90.5	11,645	GAS	33,880	1,027,745	34,820.0	122,799	4.11	3.62
44. BAYSIDE #4	56	2,410	5.8	98.6	89.7	11,743	GAS	27,540	1,027,596	28,300.0	99,819	4.14	3.62
45. BAYSIDE #5	56	4,480	10.8	98.6	89.9	11,616	GAS	50,620	1,028,052	52,040.0	183,473	4.10	3.62
46. BAYSIDE #6	56	3,960	9.5	98.6	89.5	11,646	GAS	44,860	1,028,087	46,120.0	162,596	4.11	3.62
47. BAYSIDE STATION TOTAL	**1,854**	**1,009,670**	**73.2**	**97.2**	**84.5**	**7,396**	**GAS**	**7,264,500**	**1,027,999**	**7,467,900.0**	**26,330,289**	**2.61**	**3.62**
48. SYSTEM TOTAL	**5,204**	**2,089,489**	**54.0**	**84.0**	**99.8**	**7,457**	**-**	**-**	**-**	**15,580,889.9**	**55,164,897**	**2.64**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	220	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,530	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	200	19.8	-	19.8	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	13,770	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	14,270	27.2	-	27.2	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	14,470	27.6	-	27.6	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	11,490	26.7	-	26.7	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	10,510	26.8	-	26.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	6,780	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	9,100	25.8	-	25.8	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	13,800	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	14,520	27.1	-	27.1	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**112,660**	**26.7**	**-**	**26.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**28,050**	**12.8**	**91.8**	**52.3**	**12,484**	**GAS**	**340,640**	**1,028,006**	**350,180.0**	**1,245,072**	**4.44**	**3.66**
15. BIG BEND #2 TOTAL	**340**	**54,560**	**22.3**	**91.8**	**48.0**	**11,443**	**GAS**	**607,300**	**1,028,009**	**624,310.0**	**2,219,740**	**4.07**	**3.66**
16. B.B.#3 (GAS)	345	63,520	25.6	-	-	-	GAS	683,820	1,028,004	702,970.0	2,499,428	3.93	3.66
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**63,520**	**25.6**	**92.1**	**62.2**	**11,067**		**-**	**-**	**702,970.0**	**2,499,428**	**3.93**	**-**
19. B.B.#4 (GAS)	185	7,210	5.4	-	-	-	GAS	83,530	1,028,014	85,870.0	305,310	4.23	3.66
20. B.B.#4 (COAL)	437	137,050	43.6	-	-	-	COAL	72,510	22,500,759	1,631,530.0	5,527,467	4.03	76.23
21. BIG BEND #4 TOTAL	**437**	**144,260**	**45.8**	**86.2**	**49.8**	**11,905**		**-**	**-**	**1,717,400.0**	**5,832,777**	**4.04**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	59,270	-	60,940.0	216,638	-	3.66
23. B.B.C.T.#4 TOTAL	**56**	**2,600**	**6.4**	**98.2**	**92.9**	**11,608**	**GAS**	**29,360**	**1,027,929**	**30,180.0**	**107,314**	**4.13**	**3.66**
24. BIG BEND STATION TOTAL	**1,483**	**292,990**	**27.4**	**90.5**	**52.4**	**11,690**	**-**	**-**	**-**	**3,425,040.0**	**12,120,969**	**4.14**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	35,810	23.7	-	87.0	8,323	GAS	289,910	1,028,009	298,030.0	1,059,649	2.96	3.66
27. POLK #1 TOTAL	**220**	**35,810**	**22.6**	**40.5**	**87.0**	**8,323**	**-**	**-**	**-**	**298,030.0**	**1,059,649**	**2.96**	**-**
28. POLK #2 ST DUCT FIRING	120	26,560	30.7	-	71.2	8,275	GAS	213,800	1,027,970	219,780.0	781,460	2.94	3.66
29. POLK #2 ST W/O DUCT FIRING	341	482,874	-	-	-	-		3,305,412	1,028,013	3,398,007.1	12,081,600	2.50	3.66
30. POLK #2 ST TOTAL	**461**	**509,434**	**153.5**	**-**	**108.2**	**7,102**	**GAS**	**-**	**-**	**3,617,787.1**	**12,863,060**	**2.52**	**-**
31. POLK #2 CT (GAS)	150	1,500	1.4	-	100.0	11,453	GAS	16,720	1,027,512	17,180.0	61,112	4.07	3.66
32. POLK #2 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,754	23.91	127.49
33. POLK #2 TOTAL [4]	**150**	**2,143**	**2.0**	**-**	**98.2**	**11,317**	**-**	**-**	**-**	**24,251.4**	**214,866**	**10.03**	**-**
34. POLK #3 CT (GAS)	150	1,500	1.4	-	100.0	11,400	GAS	16,640	1,027,644	17,100.0	60,821	4.05	3.66
35. POLK #3 CT (OIL)	159	643	0.6	-	94.4	10,998	LGT OIL	1,206	5,863,516	7,071.4	153,753	23.91	127.49
36. POLK #3 TOTAL [4]	**150**	**2,143**	**2.0**	**-**	**98.2**	**11,279**	**-**	**-**	**-**	**24,171.4**	**214,574**	**10.01**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**1,350**	**1.3**	**-**	**100.0**	**11,467**	**GAS**	**15,060**	**1,027,888**	**15,480.0**	**55,046**	**4.08**	**3.66**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**515,070**	**67.4**	**74.6**	**107.9**	**7,148**	**-**	**-**	**-**	**3,681,689.9**	**13,347,546**	**2.59**	**-**
40. POLK STATION TOTAL	**1,281**	**550,880**	**59.7**	**68.7**	**104.6**	**7,224**	**-**	**-**	**-**	**3,979,719.9**	**14,407,195**	**2.62**	**-**
41. BAYSIDE #1	701	424,000	84.0	97.2	86.8	7,297	GAS	3,009,690	1,028,000	3,093,960.0	11,000,707	2.59	3.66
42. BAYSIDE #2	929	498,610	74.5	96.8	76.6	7,400	GAS	3,589,110	1,027,999	3,689,600.0	13,118,543	2.63	3.66
43. BAYSIDE #3	56	6,530	16.2	98.6	99.7	11,467	GAS	72,850	1,027,865	74,880.0	266,274	4.08	3.66
44. BAYSIDE #4	56	4,400	10.9	98.6	99.5	11,573	GAS	49,530	1,028,064	50,920.0	181,037	4.11	3.66
45. BAYSIDE #5	56	9,450	23.4	98.6	99.3	11,334	GAS	104,180	1,028,124	107,110.0	380,788	4.03	3.66
46. BAYSIDE #6	56	8,430	20.9	98.6	99.7	11,342	GAS	93,000	1,028,065	95,610.0	339,924	4.03	3.66
47. BAYSIDE STATION TOTAL	**1,854**	**951,420**	**71.3**	**97.2**	**81.4**	**7,475**	**GAS**	**6,918,360**	**1,028,001**	**7,112,080.0**	**25,287,273**	**2.66**	**3.66**
48. SYSTEM TOTAL	**5,204**	**1,907,950**	**50.9**	**77.3**	**92.7**	**7,609**	**-**	**-**	**-**	**14,516,839.9**	**51,815,437**	**2.72**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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: OCTOBER 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	250	24.0	-	24.0	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,650	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	210	20.2	-	20.2	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	13,610	26.6	-	26.6	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	14,110	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	14,130	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	11,340	25.5	-	25.5	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	10,380	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	7,160	26.4	-	26.4	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	8,990	24.7	-	24.7	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	14,330	25.7	-	25.7	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	14,180	25.6	-	25.6	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**112,340**	**25.8**	**-**	**25.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**14,770**	**6.5**	**91.8**	**52.1**	**12,521**	**GAS**	**179,890**	**1,028,017**	**184,930.0**	**663,149**	**4.49**	**3.69**
15. BIG BEND #2 TOTAL	**340**	**49,970**	**19.8**	**91.8**	**50.0**	**11,355**	**GAS**	**551,950**	**1,027,992**	**567,400.0**	**2,034,715**	**4.07**	**3.69**
16. B.B.#3 (GAS)	345	66,880	26.1	-	-	-	GAS	718,440	1,028,005	738,560.0	2,648,466	3.96	3.69
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**66,880**	**26.1**	**86.1**	**63.6**	**11,043**		**-**	**-**	**738,560.0**	**2,648,466**	**3.96**	**-**
19. B.B.#4 (GAS)	185	1,670	1.2	-	-	-	GAS	20,180	1,028,246	20,750.0	74,392	4.45	3.69
20. B.B.#4 (COAL)	437	31,700	9.8	-	-	-	COAL	17,520	22,502,854	394,250.0	1,357,254	4.28	77.47
21. BIG BEND #4 TOTAL	**437**	**33,370**	**10.3**	**86.2**	**42.7**	**12,436**		**-**	**-**	**415,000.0**	**1,431,646**	**4.29**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	55,940	-	57,490.0	206,218	-	3.69
23. B.B.C.T.#4 TOTAL	**56**	**3,500**	**8.4**	**98.2**	**97.7**	**11,446**	**GAS**	**38,970**	**1,027,970**	**40,060.0**	**143,660**	**4.10**	**3.69**
24. BIG BEND STATION TOTAL	**1,483**	**168,490**	**15.3**	**89.1**	**54.0**	**11,549**	**-**	**-**	**-**	**1,945,950.0**	**7,127,854**	**4.23**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	69,480	44.5	-	88.5	8,332	GAS	563,110	1,028,005	578,880.0	2,075,856	2.99	3.69
27. POLK #1 TOTAL	**220**	**69,480**	**42.4**	**81.4**	**88.5**	**8,332**	**-**	**-**	**-**	**578,880.0**	**2,075,856**	**2.99**	**-**
28. POLK #2 ST DUCT FIRING	120	18,370	20.6	-	66.3	8,277	GAS	147,900	1,027,992	152,040.0	545,220	2.97	3.69
29. POLK #2 ST W/O DUCT FIRING	341	409,700	-	-	-	-		2,806,381	1,028,007	2,884,980.0	10,345,479	2.53	3.69
30. POLK #2 ST TOTAL	**461**	**428,070**	**124.8**	**-**	**110.3**	**7,095**	**GAS**	**-**	**-**	**3,037,020.0**	**10,890,699**	**2.54**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	86	0.1	-	94.7	10,964	LGT OIL	161	5,856,522	942.9	20,526	23.87	127.49
33. POLK #2 TOTAL [4]	**150**	**86**	**0.1**	**-**	**94.7**	**10,964**	**-**	**-**	**-**	**942.9**	**20,526**	**23.87**	**-**
34. POLK #3 CT (GAS)	150	7,390	6.6	-	96.6	11,562	GAS	83,120	1,027,911	85,440.0	306,415	4.15	3.69
35. POLK #3 CT (OIL)	159	664	0.6	-	94.3	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,853	23.92	127.49
36. POLK #3 TOTAL [4]	**150**	**8,054**	**7.2**	**-**	**96.4**	**11,516**	**-**	**-**	**-**	**92,747.1**	**465,268**	**5.78**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**5,960**	**5.3**	**-**	**96.9**	**11,579**	**GAS**	**67,120**	**1,028,159**	**69,010.0**	**247,432**	**4.15**	**3.69**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**4,010**	**3.6**	**-**	**99.0**	**11,501**	**GAS**	**44,850**	**1,028,317**	**46,120.0**	**165,336**	**4.12**	**3.69**
39. POLK #2 CC TOTAL	**1,061**	**446,180**	**56.5**	**69.4**	**108.6**	**7,275**	**-**	**-**	**-**	**3,245,840.0**	**11,789,261**	**2.64**	**-**
40. POLK STATION TOTAL	**1,281**	**515,660**	**54.1**	**71.4**	**103.0**	**7,417**	**-**	**-**	**-**	**3,824,720.0**	**13,865,117**	**2.69**	**-**
41. BAYSIDE #1	701	437,940	84.0	97.2	86.4	7,300	GAS	3,110,040	1,028,000	3,197,120.0	11,464,892	2.62	3.69
42. BAYSIDE #2	929	490,860	71.0	96.8	74.5	7,419	GAS	3,542,490	1,027,997	3,641,670.0	13,059,081	2.66	3.69
43. BAYSIDE #3	56	4,810	11.5	98.6	97.6	11,511	GAS	53,860	1,028,036	55,370.0	198,550	4.13	3.69
44. BAYSIDE #4	56	3,620	8.7	98.6	97.9	11,528	GAS	40,590	1,028,086	41,730.0	149,632	4.13	3.69
45. BAYSIDE #5	56	6,620	15.9	98.6	98.5	11,391	GAS	73,370	1,027,804	75,410.0	270,472	4.09	3.69
46. BAYSIDE #6	56	5,890	14.1	98.6	99.2	11,411	GAS	65,370	1,028,147	67,210.0	240,981	4.09	3.69
47. BAYSIDE STATION TOTAL	**1,854**	**949,740**	**68.9**	**97.2**	**80.0**	**7,453**	**GAS**	**6,885,720**	**1,027,999**	**7,078,510.0**	**25,383,608**	**2.67**	**3.69**
48. SYSTEM TOTAL	**5,204**	**1,746,230**	**45.1**	**77.6**	**95.0**	**7,358**	**-**	**-**	**-**	**12,849,180.0**	**46,376,579**	**2.66**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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: NOVEMBER 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	230	22.8	-	22.8	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	3,020	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	160	15.9	-	15.9	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	10,170	20.5	-	20.5	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	10,540	20.1	-	20.1	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	12,110	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	8,450	19.7	-	19.7	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	7,740	19.8	-	19.8	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	6,060	23.1	-	23.1	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	6,730	19.1	-	19.1	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	11,840	22.0	-	22.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	12,150	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**89,200**	**21.2**	**-**	**21.2**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**305**	**25,330**	**11.5**	**91.8**	**43.3**	**13,218**	**GAS**	**325,700**	**1,028,001**	**334,820.0**	**1,220,896**	**4.82**	**3.75**
15. BIG BEND #2 TOTAL	**340**	**31,630**	**12.9**	**91.8**	**45.2**	**11,630**	**GAS**	**357,860**	**1,027,972**	**367,870.0**	**1,341,448**	**4.24**	**3.75**
16. B.B.#3 (GAS)	345	30,760	12.4	-	-	-	GAS	333,610	1,027,997	342,950.0	1,250,546	4.07	3.75
17. B.B.#3 (COAL)	395	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**345**	**30,760**	**12.4**	**67.5**	**60.2**	**11,149**		**-**	**-**	**342,950.0**	**1,250,546**	**4.07**	**-**
19. B.B.#4 (GAS)	185	2,890	2.2	-	-	-	GAS	35,340	1,028,014	36,330.0	132,473	4.58	3.75
20. B.B.#4 (COAL)	437	54,970	17.5	-	-	-	COAL	30,680	22,500,652	690,320.0	2,342,690	4.26	76.36
21. BIG BEND #4 TOTAL	**437**	**57,860**	**18.4**	**83.3**	**41.5**	**12,559**		**-**	**-**	**726,650.0**	**2,475,163**	**4.28**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	52,600	-	54,080.0	197,173	-	3.75
23. B.B.C.T.#4 TOTAL	**56**	**790**	**2.0**	**98.2**	**67.2**	**12,899**	**GAS**	**9,910**	**1,028,254**	**10,190.0**	**37,148**	**4.70**	**3.75**
24. BIG BEND STATION TOTAL	**1,483**	**146,370**	**13.7**	**83.9**	**45.9**	**12,178**	**-**	**-**	**-**	**1,782,480.0**	**6,522,374**	**4.46**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	210	69,890	46.2	-	88.0	8,255	GAS	561,220	1,028,010	576,940.0	2,103,749	3.01	3.75
27. POLK #1 TOTAL	**220**	**69,890**	**44.1**	**93.4**	**88.0**	**8,255**	**-**	**-**	**-**	**576,940.0**	**2,103,749**	**3.01**	**-**
28. POLK #2 ST DUCT FIRING	120	16,260	18.8	-	64.8	8,274	GAS	130,870	1,027,967	134,530.0	490,570	3.02	3.75
29. POLK #2 ST W/O DUCT FIRING	341	477,397	-	-	-	-		3,270,672	1,028,008	3,362,278.6	12,260,208	2.57	3.75
30. POLK #2 ST TOTAL	**461**	**493,657**	**148.7**	**-**	**116.5**	**7,083**	**GAS**	**-**	**-**	**3,496,808.6**	**12,750,778**	**2.58**	**-**
31. POLK #2 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	159	450	0.4	-	94.3	11,000	LGT OIL	844	5,864,929	4,950.0	107,590	23.91	127.48
33. POLK #2 TOTAL [4]	**150**	**450**	**0.4**	**-**	**94.3**	**11,000**	**-**	**-**	**-**	**4,950.0**	**107,590**	**23.91**	**-**
34. POLK #3 CT (GAS)	150	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	159	493	0.4	-	94.4	10,997	LGT OIL	925	5,860,973	5,421.4	117,915	23.92	127.48
36. POLK #3 TOTAL [4]	**150**	**493**	**0.5**	**-**	**94.4**	**10,997**	**-**	**-**	**-**	**5,421.4**	**117,915**	**23.92**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**150**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,061**	**494,600**	**64.7**	**80.4**	**116.4**	**7,091**	**-**	**-**	**-**	**3,507,180.0**	**12,976,283**	**2.62**	**-**
40. POLK STATION TOTAL	**1,281**	**564,490**	**61.2**	**82.6**	**108.2**	**7,235**	**-**	**-**	**-**	**4,084,120.0**	**15,080,032**	**2.67**	**-**
41. BAYSIDE #1	701	403,520	79.9	97.2	82.1	7,319	GAS	2,872,790	1,028,001	2,953,230.0	10,768,736	2.67	3.75
42. BAYSIDE #2	929	222,600	33.3	58.1	64.8	7,492	GAS	1,622,340	1,027,990	1,667,750.0	6,081,387	2.73	3.75
43. BAYSIDE #3	56	1,460	3.6	98.6	81.5	12,274	GAS	17,430	1,028,112	17,920.0	65,337	4.48	3.75
44. BAYSIDE #4	56	1,290	3.2	98.6	82.3	12,147	GAS	15,250	1,027,541	15,670.0	57,165	4.43	3.75
45. BAYSIDE #5	56	2,360	5.9	98.6	84.3	11,979	GAS	27,500	1,028,000	28,270.0	103,085	4.37	3.75
46. BAYSIDE #6	56	2,060	5.1	98.6	83.6	12,039	GAS	24,120	1,028,192	24,800.0	90,415	4.39	3.75
47. BAYSIDE STATION TOTAL	**1,854**	**633,290**	**47.4**	**77.8**	**75.1**	**7,434**	**GAS**	**4,579,430**	**1,027,997**	**4,707,640.0**	**17,166,125**	**2.71**	**3.75**
48. SYSTEM TOTAL	**5,204**	**1,433,350**	**38.3**	**72.0**	**94.6**	**7,377**	**-**	**-**	**-**	**10,574,240.0**	**38,768,531**	**2.70**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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: DECEMBER 2020

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.4	220	21.1	-	21.1	-	SOLAR	-	-	-	-	-	-
2. BIG BEND SOLAR	19.2	2,740	19.2	-	19.2	-	SOLAR	-	-	-	-	-	-
3. LEGOLAND SOLAR	1.4	150	14.4	-	14.4	-	SOLAR	-	-	-	-	-	-
4. PAYNE CREEK SOLAR	68.9	8,540	16.7	-	16.7	-	SOLAR	-	-	-	-	-	-
5. BALM SOLAR	72.9	8,840	16.3	-	16.3	-	SOLAR	-	-	-	-	-	-
6. LITHIA SOLAR	72.9	10,490	19.3	-	19.3	-	SOLAR	-	-	-	-	-	-
7. GRANGE HALL SOLAR	59.7	7,100	16.0	-	16.0	-	SOLAR	-	-	-	-	-	-
8. PEACE CREEK SOLAR	54.4	6,510	16.1	-	16.1	-	SOLAR	-	-	-	-	-	-
9. BONNIE MINE SOLAR	36.5	5,080	18.7	-	18.7	-	SOLAR	-	-	-	-	-	-
10. LAKE HANCOCK SOLAR	48.9	5,650	15.5	-	15.5	-	SOLAR	-	-	-	-	-	-
11. WIMAUMA SOLAR	74.8	10,560	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
12. LITTLE MANATEE RIVER SOLAR	74.5	10,550	19.0	-	19.0	-	SOLAR	-	-	-	-	-	-
13. SOLAR TOTAL [3]	**585.5**	**76,430**	**17.5**	**-**	**17.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
14. BIG BEND #1 TOTAL	**315**	**6,140**	**2.6**	**91.8**	**40.6**	**13,246**	**GAS**	**79,120**	**1,027,932**	**81,330.0**	**308,823**	**5.03**	**3.90**
15. BIG BEND #2 TOTAL	**350**	**22,310**	**8.6**	**91.8**	**41.9**	**11,656**	**GAS**	**252,950**	**1,028,029**	**260,040.0**	**987,320**	**4.43**	**3.90**
16. B.B.#3 (GAS)	355	17,290	6.5	-	-	-	GAS	184,170	1,028,018	189,330.0	718,857	4.16	3.90
17. B.B.#3 (COAL)	400	0	0.0	-	-	-	COAL	0	0	0.0	0	0.00	0.00
18. BIG BEND #3 TOTAL	**355**	**17,290**	**6.5**	**92.1**	**61.7**	**10,950**		**-**	**-**	**189,330.0**	**718,857**	**4.16**	**-**
19. B.B.#4 (GAS)	195	3,940	2.7	-	-	-	GAS	49,440	1,028,115	50,830.0	192,975	4.90	3.90
20. B.B.#4 (COAL)	442	74,910	22.8	-	-	-	COAL	42,920	22,500,233	965,710.0	3,262,642	4.36	76.02
21. BIG BEND #4 TOTAL	**442**	**78,850**	**24.0**	**61.1**	**36.7**	**12,892**		**-**	**-**	**1,016,540.0**	**3,455,617**	**4.38**	**-**
22. B.B. IGNITION	-	-	-	-	-	-	GAS	28,390	-	29,180.0	110,813	-	3.90
23. B.B.C.T.#4 TOTAL	**61**	**850**	**1.9**	**98.2**	**92.9**	**11,471**	**GAS**	**9,480**	**1,028,481**	**9,750.0**	**37,003**	**4.35**	**3.90**
24. BIG BEND STATION TOTAL	**1,523**	**125,440**	**11.1**	**83.2**	**40.3**	**12,412**	**-**	**-**	**-**	**1,556,990.0**	**5,618,433**	**4.48**	**-**
25. POLK #1 GASIFIER	220	0	0.0	-	0.0	0	COAL	0	0	0.0	0	0.00	0.00
26. POLK #1 CT (GAS)	230	40,240	23.5	-	86.6	8,308	GAS	325,220	1,027,981	334,320.0	1,269,407	3.15	3.90
27. POLK #1 TOTAL	**230**	**40,240**	**23.5**	**93.4**	**86.6**	**8,308**	**-**	**-**	**-**	**334,320.0**	**1,269,407**	**3.15**	**-**
28. POLK #2 ST DUCT FIRING	120	15,540	17.4	-	94.5	8,169	GAS	123,490	1,028,018	126,950.0	482,009	3.10	3.90
29. POLK #2 ST W/O DUCT FIRING	360	496,581	-	-	-	-		3,488,192	1,028,010	3,585,895.7	13,615,196	2.74	3.90
30. POLK #2 ST TOTAL	**480**	**512,121**	**143.4**	**-**	**122.9**	**7,250**	**GAS**	**-**	**-**	**3,712,845.7**	**14,097,205**	**2.75**	**-**
31. POLK #2 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. POLK #2 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,879	23.93	127.51
33. POLK #2 TOTAL [4]	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,879**	**23.93**	**-**
34. POLK #3 CT (GAS)	180	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. POLK #3 CT (OIL)	187	664	0.5	-	80.2	11,005	LGT OIL	1,246	5,864,446	7,307.1	158,878	23.93	127.51
36. POLK #3 TOTAL [4]	**180**	**664**	**0.5**	**-**	**80.2**	**11,005**	**-**	**-**	**-**	**7,307.1**	**158,878**	**23.93**	**-**
37. POLK #4 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
38. POLK #5 CT (GAS) TOTAL [4]	**180**	**0**	**0.0**	**-**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
39. POLK #2 CC TOTAL	**1,200**	**513,449**	**57.5**	**97.2**	**122.5**	**7,260**	**-**	**-**	**-**	**3,727,459.9**	**14,414,962**	**2.81**	**-**
40. POLK STATION TOTAL	**1,430**	**553,689**	**52.0**	**96.6**	**115.8**	**7,336**	**-**	**-**	**-**	**4,061,779.9**	**15,684,369**	**2.83**	**-**
41. BAYSIDE #1	792	267,500	45.4	59.6	79.8	7,208	GAS	1,875,630	1,028,007	1,928,160.0	7,321,005	2.74	3.90
42. BAYSIDE #2	1,047	494,800	63.5	96.8	65.3	7,399	GAS	3,561,390	1,028,000	3,661,110.0	13,900,905	2.81	3.90
43. BAYSIDE #3	61	1,740	3.8	98.6	92.0	11,391	GAS	19,270	1,028,542	19,820.0	75,215	4.32	3.90
44. BAYSIDE #4	61	1,100	2.4	98.6	94.9	11,445	GAS	12,250	1,027,755	12,590.0	47,814	4.35	3.90
45. BAYSIDE #5	61	2,340	5.2	98.6	93.6	11,316	GAS	25,760	1,027,950	26,480.0	100,547	4.30	3.90
46. BAYSIDE #6	61	2,230	4.9	98.6	93.7	11,318	GAS	24,550	1,028,106	25,240.0	95,824	4.30	3.90
47. BAYSIDE STATION TOTAL	**2,083**	**769,710**	**49.7**	**82.9**	**69.9**	**7,371**	**GAS**	**5,518,850**	**1,028,004**	**5,673,400.0**	**21,541,310**	**2.80**	**3.90**
48. SYSTEM TOTAL	**5,622**	**1,525,269**	**36.5**	**77.8**	**87.6**	**7,403**	**-**	**-**	**-**	**11,292,169.9**	**42,844,112**	**2.81**	**-**

LEGEND:
B.B. = BIG BEND **CT = COMBUSTION TURBINE**
CC = COMBINED CYCLE **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 2020 THROUGH JUNE 2020

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
	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	0	0	0
16.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
17.	AMOUNT ($)	0	0	0	0	0	0
18.	BURNED:						
19.	UNITS (BBL)	2,492	2,332	2,492	1,890	2,331	2,412
20.	UNIT COST ($/BBL)	127.51	127.47	127.51	127.45	127.52	127.49
21.	AMOUNT ($)	317,757	297,257	317,757	240,881	297,257	307,507
22.	ENDING INVENTORY:						
23.	UNITS (BBL)	27,046	24,715	22,222	20,332	18,001	15,589
24.	UNIT COST ($/BBL)	127.48	127.48	127.48	127.49	127.48	127.48
25.	AMOUNT ($)	3,447,942	3,150,685	2,832,927	2,592,047	2,294,790	1,987,283
26.	DAYS SUPPLY: NORMAL	366,407	334,828	300,231	274,696	243,203	210,616
27.	DAYS SUPPLY: EMERGENCY	4	4	3	3	3	2
	COAL						
28.	PURCHASES:						
29.	UNITS (TONS)	0	0	0	0	0	0
30.	UNIT COST ($/TON)	0.00	0.00	0.00	0.00	0.00	0.00
31.	AMOUNT ($)	0	0	0	0	0	0
32.	BURNED:						
33.	UNITS (TONS)	62,380	3,830	0	10,610	1,840	28,040
34.	UNIT COST ($/TON)	76.89	71.68	0.00	77.72	77.26	76.16
35.	AMOUNT ($)	4,796,166	274,531	0	824,594	142,161	2,135,479
36.	ENDING INVENTORY:						
37.	UNITS (TONS)	367,992	364,162	364,162	353,552	351,712	323,672
38.	UNIT COST ($/TON)	70.17	70.19	70.19	70.26	70.27	70.48
39.	AMOUNT ($)	25,820,616	25,560,286	25,560,286	24,839,949	24,714,989	22,810,928
40.	DAYS SUPPLY:	506	2,270	2,691	795	326	177
	NATURAL GAS						
41.	PURCHASES:						
42.	UNITS (MCF)	9,335,262	8,907,432	9,459,532	11,144,069	12,315,877	13,351,492
43.	UNIT COST ($/MCF)	4.26	4.21	4.03	3.55	3.54	3.58
44.	AMOUNT ($)	39,790,461	37,540,967	38,164,838	39,544,044	43,617,012	47,828,357
45.	BURNED:						
46.	UNITS (MCF)	9,335,262	8,907,432	9,459,532	10,268,582	11,926,772	13,351,492
47.	UNIT COST ($/MCF)	4.26	4.22	4.04	3.63	3.58	3.58
48.	AMOUNT ($)	39,767,061	37,560,467	38,204,138	37,303,944	42,650,612	47,794,757
49.	ENDING INVENTORY:						
50.	UNITS (MCF)	291,829	291,829	291,829	1,167,315	1,556,420	1,556,420
51.	UNIT COST ($/MCF)	3.23	3.17	3.03	2.68	2.63	2.65
52.	AMOUNT ($)	943,500	924,000	884,700	3,124,800	4,091,200	4,124,800
53.	DAYS SUPPLY:	1	1	1	3	4	4
	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 ADJUSTMENTS (3) GAS-IGNITION

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2020 THROUGH DECEMBER 2020

		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	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)	0	0	0	0	0	0	0
16.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17.	AMOUNT ($)	0	0	0	0	0	0	0
18.	BURNED:							
19.	UNITS (BBL)	2,492	2,492	2,412	1,407	1,769	2,492	27,013
20.	UNIT COST ($/BBL)	127.51	127.51	127.49	127.49	127.48	127.51	127.50
21.	AMOUNT ($)	317,757	317,757	307,507	179,379	225,505	317,757	3,444,078
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	13,096	10,604	8,191	6,784	5,015	2,523	2,523
24.	UNIT COST ($/BBL)	127.48	127.48	127.49	127.49	127.49	127.48	127.48
25.	AMOUNT ($)	1,669,526	1,351,768	1,044,261	864,882	639,377	321,620	321,620
26.	DAYS SUPPLY: NORMAL	176,934	143,266	110,665	91,655	67,755	34,087	-
27.	DAYS SUPPLY: EMERGENCY	2	2	1	1	1	0	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	0	40,000	70,000	27,500	42,500	27,500	207,500
30.	UNIT COST ($/TON)	0.00	63.66	59.98	61.36	59.14	61.36	60.88
31.	AMOUNT ($)	0	2,546,517	4,198,580	1,687,421	2,513,453	1,687,421	12,633,392
32.	BURNED:							
33.	UNITS (TONS)	69,440	71,090	72,510	17,520	30,680	42,920	410,860
34.	UNIT COST ($/TON)	76.35	76.28	76.23	77.47	76.36	76.02	76.40
35.	AMOUNT ($)	5,301,860	5,422,957	5,527,467	1,357,254	2,342,690	3,262,642	31,387,801
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	254,232	223,142	220,632	230,612	242,432	227,012	227,012
38.	UNIT COST ($/TON)	71.18	71.19	69.71	69.13	68.10	68.24	68.24
39.	AMOUNT ($)	18,096,463	15,885,874	15,380,446	15,942,031	16,510,124	15,492,146	15,492,146
40.	DAYS SUPPLY:	110	127	166	233	164	187	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	13,150,682	13,636,082	12,579,822	12,163,571	9,268,107	10,059,302	135,371,230
43.	UNIT COST ($/MCF)	3.64	3.62	3.65	3.69	3.80	3.92	3.76
44.	AMOUNT ($)	47,836,229	49,424,183	45,951,663	44,873,546	35,207,936	39,443,713	509,222,949
45.	BURNED:							
46.	UNITS (MCF)	13,150,682	13,636,082	12,579,822	12,163,571	9,657,212	10,059,302	134,495,743
47.	UNIT COST ($/MCF)	3.63	3.62	3.66	3.69	3.75	3.90	3.77
48.	AMOUNT ($)	47,794,629	49,424,183	45,980,463	44,839,946	36,200,336	39,263,713	506,784,249
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	1,556,420	1,556,420	1,556,420	1,556,420	1,167,315	1,167,315	1,167,315
51.	UNIT COST ($/MCF)	2.68	2.68	2.66	2.68	2.72	2.88	2.88
52.	AMOUNT ($)	4,166,400	4,166,400	4,137,600	4,171,200	3,178,800	3,358,800	3,358,800
53.	DAYS SUPPLY:	4	4	4	4	3	3	-
	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 **SCHEDULE E6**
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH JUNE 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH WHEELED		CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON SALES
Jan-20	SEMINOLE	JURISD. SCH. - D	610.0	0.0	610.0	2.746	2.910	16,750.00	17,750.00	1,000.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**610.0**	**0.0**	**610.0**	**2.746**	**2.910**	**16,750.00**	**17,750.00**	**1,000.00**
Feb-20	SEMINOLE	JURISD. SCH. - D	560.0	0.0	560.0	2.755	2.920	15,430.00	16,352.00	922.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**560.0**	**0.0**	**560.0**	**2.755**	**2.920**	**15,430.00**	**16,352.00**	**922.00**
Mar-20	SEMINOLE	JURISD. SCH. - D	530.0	0.0	530.0	2.851	3.021	15,110.00	16,012.00	902.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**530.0**	**0.0**	**530.0**	**2.851**	**3.021**	**15,110.00**	**16,012.00**	**902.00**
Apr-20	SEMINOLE	JURISD. SCH. - D	600.0	0.0	600.0	2.797	2.964	16,780.00	17,782.00	1,002.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**600.0**	**0.0**	**600.0**	**2.797**	**2.964**	**16,780.00**	**17,782.00**	**1,002.00**
May-20	SEMINOLE	JURISD. SCH. - D	570.0	0.0	570.0	3.160	3.348	18,010.00	19,086.00	1,076.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**570.0**	**0.0**	**570.0**	**3.160**	**3.348**	**18,010.00**	**19,086.00**	**1,076.00**
Jun-20	SEMINOLE	JURISD. SCH. - D	580.0	0.0	580.0	3.059	3.241	17,740.00	18,800.00	1,060.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**580.0**	**0.0**	**580.0**	**3.059**	**3.241**	**17,740.00**	**18,800.00**	**1,060.00**

TAMPA ELECTRIC COMPANY **SCHEDULE E6**

POWER SOLD

ESTIMATED FOR THE PERIOD: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH WHEELED		CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON SALES
Jul-20	SEMINOLE	JURISD. SCH. - D	580.0	0.0	580.0	2.764	2.929	16,030.00	16,987.00	957.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**580.0**	**0.0**	**580.0**	**2.764**	**2.929**	**16,030.00**	**16,987.00**	**957.00**
Aug-20	SEMINOLE	JURISD. SCH. - D	580.0	0.0	580.0	2.721	2.883	15,780.00	16,722.00	942.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**580.0**	**0.0**	**580.0**	**2.721**	**2.883**	**15,780.00**	**16,722.00**	**942.00**
Sep-20	SEMINOLE	JURISD. SCH. - D	570.0	0.0	570.0	3.151	3.339	17,960.00	19,033.00	1,073.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**570.0**	**0.0**	**570.0**	**3.151**	**3.339**	**17,960.00**	**19,033.00**	**1,073.00**
Oct-20	SEMINOLE	JURISD. SCH. - D	580.0	0.0	580.0	2.602	2.757	15,090.00	15,991.00	901.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**580.0**	**0.0**	**580.0**	**2.602**	**2.757**	**15,090.00**	**15,991.00**	**901.00**
Nov-20	SEMINOLE	JURISD. SCH. - D	570.0	0.0	570.0	2.819	2.988	16,070.00	17,030.00	960.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**570.0**	**0.0**	**570.0**	**2.819**	**2.988**	**16,070.00**	**17,030.00**	**960.00**
Dec-20	SEMINOLE	JURISD. SCH. - D	580.0	0.0	580.0	2.740	2.903	15,890.00	16,839.00	949.00
	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	TOTAL		**580.0**	**0.0**	**580.0**	**2.740**	**2.903**	**15,890.00**	**16,839.00**	**949.00**
TOTAL										
Jan-20	SEMINOLE	JURISD. SCH. - D	6,910.0	0.0	6,910.0	2.846	3.016	196,640.00	208,384.00	11,744.00
THRU	VARIOUS	JURISD. MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
Dec-20	**TOTAL**		**6,910.0**	**0.0**	**6,910.0**	**2.846**	**3.016**	**196,640.00**	**208,384.00**	**11,744.00**

TAMPA ELECTRIC COMPANY **SCHEDULE E7**
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jan-20	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-20	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-20	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-20	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-20	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-20	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-20	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-20	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-20	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-20	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-20	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-20	VARIOUS	FIRM	1,900.0	0.0	0.0	1,900.0	4.107	4.107	78,030.00
	TOTAL		**1,900.0**	**0.0**	**0.0**	**1,900.0**	**4.107**	**4.107**	**78,030.00**
TOTAL Jan-20 THRU Dec-20	VARIOUS	FIRM	1,900.0	0.0	0.0	1,900.0	4.107	4.107	78,030.00
	TOTAL		**1,900.0**	**0.0**	**0.0**	**1,900.0**	**4.107**	**4.107**	**78,030.00**

TAMPA ELECTRIC COMPANY **SCHEDULE E8**
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUST-MENT
Jan-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,550.0	0.0	0.0	10,550.0	2.676	2.676	282,290.00
	TOTAL		**10,550.0**	**0.0**	**0.0**	**10,550.0**	**2.676**	**2.676**	**282,290.00**
Feb-20	VARIOUS	CO-GEN.							
		AS AVAIL.	9,970.0	0.0	0.0	9,970.0	2.750	2.750	274,130.00
	TOTAL		**9,970.0**	**0.0**	**0.0**	**9,970.0**	**2.750**	**2.750**	**274,130.00**
Mar-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,360.0	0.0	0.0	10,360.0	2.761	2.761	286,020.00
	TOTAL		**10,360.0**	**0.0**	**0.0**	**10,360.0**	**2.761**	**2.761**	**286,020.00**
Apr-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,280.0	0.0	0.0	10,280.0	2.850	2.850	293,010.00
	TOTAL		**10,280.0**	**0.0**	**0.0**	**10,280.0**	**2.850**	**2.850**	**293,010.00**
May-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,380.0	0.0	0.0	10,380.0	2.954	2.954	306,640.00
	TOTAL		**10,380.0**	**0.0**	**0.0**	**10,380.0**	**2.954**	**2.954**	**306,640.00**
Jun-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,250.0	0.0	0.0	10,250.0	2.931	2.931	300,450.00
	TOTAL		**10,250.0**	**0.0**	**0.0**	**10,250.0**	**2.931**	**2.931**	**300,450.00**
Jul-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,400.0	0.0	0.0	10,400.0	3.146	3.146	327,220.00
	TOTAL		**10,400.0**	**0.0**	**0.0**	**10,400.0**	**3.146**	**3.146**	**327,220.00**
Aug-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,420.0	0.0	0.0	10,420.0	3.193	3.193	332,740.00
	TOTAL		**10,420.0**	**0.0**	**0.0**	**10,420.0**	**3.193**	**3.193**	**332,740.00**
Sep-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,220.0	0.0	0.0	10,220.0	2.842	2.842	290,490.00
	TOTAL		**10,220.0**	**0.0**	**0.0**	**10,220.0**	**2.842**	**2.842**	**290,490.00**
Oct-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,450.0	0.0	0.0	10,450.0	3.266	3.266	341,270.00
	TOTAL		**10,450.0**	**0.0**	**0.0**	**10,450.0**	**3.266**	**3.266**	**341,270.00**
Nov-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,270.0	0.0	0.0	10,270.0	3.438	3.438	353,060.00
	TOTAL		**10,270.0**	**0.0**	**0.0**	**10,270.0**	**3.438**	**3.438**	**353,060.00**
Dec-20	VARIOUS	CO-GEN.							
		AS AVAIL.	10,380.0	0.0	0.0	10,380.0	2.827	2.827	293,490.00
	TOTAL		**10,380.0**	**0.0**	**0.0**	**10,380.0**	**2.827**	**2.827**	**293,490.00**
TOTAL	VARIOUS	CO-GEN.							
Jan-20		AS AVAIL.	123,930.0	0.0	0.0	123,930.0	2.970	2.970	3,680,810.00
THRU	TOTAL		**123,930.0**	**0.0**	**0.0**	**123,930.0**	**2.970**	**2.970**	**3,680,810.00**
Dec-20									

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) DOLLARS	FUEL SAVINGS (9B)-(8)
Jan-20	VARIOUS	ECONOMY	340.0	0.0	340.0	5.141	17,480.00	79.679	270,910.00	253,430.00
Feb-20	VARIOUS	ECONOMY	1,100.0	0.0	1,100.0	4.183	46,010.00	48.922	538,140.00	492,130.00
Mar-20	VARIOUS	ECONOMY	5,830.0	0.0	5,830.0	3.952	230,400.00	14.414	840,360.00	609,960.00
Apr-20	VARIOUS	ECONOMY	3,300.0	0.0	3,300.0	3.788	124,990.00	49.790	1,643,070.00	1,518,080.00
May-20	VARIOUS	ECONOMY	12,600.0	0.0	12,600.0	4.240	534,220.00	21.411	2,697,770.00	2,163,550.00
Jun-20	VARIOUS	ECONOMY	10,590.0	0.0	10,590.0	4.930	522,050.00	15.393	1,630,150.00	1,108,100.00
Jul-20	VARIOUS	ECONOMY	2,710.0	0.0	2,710.0	6.595	178,720.00	60.756	1,646,490.00	1,467,770.00
Aug-20	VARIOUS	ECONOMY	7,150.0	0.0	7,150.0	6.154	440,030.00	28.235	2,018,830.00	1,578,800.00
Sep-20	VARIOUS	ECONOMY	7,430.0	0.0	7,430.0	4.702	349,380.00	29.948	2,225,100.00	1,875,720.00
Oct-20	VARIOUS	ECONOMY	24,680.0	0.0	24,680.0	4.740	1,169,790.00	13.007	3,210,200.00	2,040,410.00
Nov-20	VARIOUS	ECONOMY	6,450.0	0.0	6,450.0	3.786	244,200.00	15.353	990,270.00	746,070.00
Dec-20	VARIOUS	ECONOMY	3,940.0	0.0	3,940.0	5.108	201,250.00	26.414	1,040,720.00	839,470.00
TOTAL	VARIOUS	ECONOMY	**86,120.0**	**0.0**	**86,120.0**	**4.713**	**4,058,520.00**	**21.774**	**18,752,010.00**	**14,693,490.00**

DOCKET NO. 20190001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 28 OF 30

SCHEDULE E10

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current Apr 2019 - Dec 2019	Projected Jan 2020	Projected Feb 2020 - Dec 2020	Difference[1] $	Difference[1] %
Base Rate Revenue	66.53	68.08	68.08	1.55	2.3%
Fuel Recovery Revenue	29.13	27.02	27.02	(2.11)	-7.2%
Conservation Revenue	3.21	2.32	2.32	(0.89)	-27.7%
Capacity Revenue	-0.10	0.10	0.10	0.20	-200.0%
Environmental Revenue	2.22	2.44	2.44	0.22	9.9%
Final Tax Savings Credit	0.00	-9.06	0.00		
Florida Gross Receipts Tax Revenue	2.59	2.33	2.56	(0.03)	-1.2%
TOTAL REVENUE	**$103.58**	**$93.23**	**$102.52**	**($1.06)**	**-1.0%**

[1]Difference does not include effect of Final Tax Savings Credit included in January 2020 bills. If included, the total difference is ($10.35) or -10.0%

DOCKET NO. 20190001-EI
EXHIBIT NO. PAR-3
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SCHEDULE H1

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
PERIOD: JANUARY THROUGH DECEMBER

	ACTUAL 2017	ACTUAL 2018	ACT/EST 2019	EST 2020	DIFFERENCE (%) 2018-2017	2019-2018	2020-2019
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL {1}	10,825	51,583	1,843,356	3,444,078	376.5%	3473.6%	86.8%
3 COAL	198,469,769	125,828,296	46,074,730	31,387,801	-36.6%	-63.4%	-31.9%
4 NATURAL GAS	412,107,824	505,830,903	508,630,766	506,784,249	22.7%	0.6%	-0.4%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**610,588,418**	**631,710,782**	**556,548,852**	**541,616,128**	**3.5%**	**-11.9%**	**-2.7%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL {1}	36	173	7,651	14,397	380.6%	4322.5%	88.2%
10 COAL	6,013,495	3,533,451	1,172,863	747,700	-41.2%	-66.8%	-36.3%
11 NATURAL GAS	13,685,288	16,096,514	17,520,700	18,120,647	17.6%	8.8%	3.4%
12 NUCLEAR	0	118,322	775,222	1,413,420	0.0%	555.2%	82.3%
13 OTHER	44,594	0	0	0	-100.0%	0.0%	0.0%
14 TOTAL (MWH)	**19,743,413**	**19,748,460**	**19,476,436**	**20,296,164**	**0.0%**	**-1.4%**	**4.2%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) {1}	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) {1}	85	405	14,458	27,013	376.5%	3469.9%	86.8%
17 COAL (TON)	2,655,830	1,626,026	596,461	410,860	-38.8%	-63.3%	-31.1%
18 NATURAL GAS (MCF)	100,512,457	121,581,188	132,814,975	134,495,743	21.0%	9.2%	1.3%
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}	495	1,349	84,772	158,399	172.5%	6184.0%	86.9%
23 COAL	64,801,532	38,881,879	13,661,025	9,244,440	-40.0%	-64.9%	-32.3%
24 NATURAL GAS	102,771,003	124,229,756	135,901,765	137,754,760	20.9%	9.4%	1.4%
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)	**167,573,029**	**163,112,984**	**149,647,562**	**147,157,599**	**-2.7%**	**-8.3%**	**-1.7%**
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	0.00	0.04	0.07	0.0%	0.0%	75.0%
30 COAL	30.45	17.89	6.02	3.69	-41.2%	-66.3%	-38.7%
31 NATURAL GAS	69.32	81.51	89.96	89.28	17.6%	10.4%	-0.8%
32 NUCLEAR	0.00	0.60	3.98	6.96	0.0%	563.3%	74.9%
33 OTHER	0.23	0.00	0.00	0.00	-100.0%	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}	127.35	127.37	127.50	127.50	0.0%	0.1%	0.0%
37 COAL ($/TON)	74.73	77.38	77.25	76.40	3.5%	-0.2%	-1.1%
38 NATURAL GAS ($/MCF)	4.10	4.16	3.83	3.77	1.5%	-7.9%	-1.6%
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}	21.87	38.24	21.74	21.74	74.9%	-43.1%	0.0%
43 COAL	3.06	3.24	3.37	3.40	5.9%	4.0%	0.9%
44 NATURAL GAS	4.01	4.07	3.74	3.68	1.5%	-8.1%	-1.6%
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)	**3.64**	**3.87**	**3.72**	**3.68**	**6.3%**	**-3.9%**	**-1.1%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL {1}	13,750	7,798	11,080	11,002	-43.3%	42.1%	-0.7%
50 COAL	10,776	11,004	11,648	12,364	2.1%	5.9%	6.1%
51 NATURAL GAS	7,510	7,718	7,757	7,602	2.8%	0.5%	-2.0%
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)	**8,488**	**8,260**	**7,684**	**7,251**	**-2.7%**	**-7.0%**	**-5.6%**
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}	30.07	29.82	24.09	23.92	-0.8%	-19.2%	-0.7%
57 COAL	3.30	3.56	3.93	4.20	7.9%	10.4%	6.9%
58 NATURAL GAS	3.01	3.14	2.90	2.80	4.3%	-7.6%	-3.4%
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)	**3.09**	**3.20**	**2.86**	**2.67**	**3.6%**	**-10.6%**	**-6.6%**

{1} DISTILLATE (BBLS, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

LEVELIZED AND TIERED FUEL RATE

JANUARY 2020 - DECEMBER 2020

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2020 through December 2020

	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	6,502,646	3.016	196,119,803	2.702	175,698,454
TIER II (Over 1,000) kWh	2,977,076	3.016	89,788,612	3.702	110,209,961
Total	9,479,722		285,908,415		285,908,415

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

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

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$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	$20,910,348	$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	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	
9	DEPRECIATION EXPENSE	$348,506	$348,506	$348,506	$348,506	$238,475	-	-	-	-	-	-	-	$1,632,498
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	$19,277,850	$19,626,355	$19,974,861	$20,323,367	$20,671,873	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$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	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348	$20,910,348
13														
14														
15	ENDING NET INVESTMENT	$1,283,993	$935,487	$586,981	$238,475	$0	$0	$0	$0	$0	$0	$0	$0	$0
16														
17														
18	AVERAGE INVESTMENT	$1,458,246	$1,109,740	$761,234	$412,728	$119,238	$0	$0	$0	$0	$0	$0	$0	
19	ALLOWED EQUITY RETURN	.37413%	.37413%	.37413%	.37413%	.37413%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	
20	EQUITY COMPONENT AFTER-TAX	$5,456	$4,152	$2,848	$1,544	$446	$0	$0	$0	$0	$0	$0	$0	$14,446
21	CONVERSION TO PRE-TAX	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	1.34295	
22	EQUITY COMPONENT PRE-TAX	$7,327	$5,576	$3,825	$2,074	$599	$0	$0	$0	$0	$0	$0	$0	$19,401
23														
24	ALLOWED DEBT RETURN	.14474%	.14474%	.14474%	.14474%	.14474%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%	.00000%
25	DEBT COMPONENT	$2,111	$1,606	$1,102	$597	$173	$0	$0	$0	$0	$0	$0	$0	$5,589
26	TAX REFORM TRUEUP													
27	TOTAL RETURN REQUIREMENTS	$9,438	$7,182	$4,927	$2,671	$772	$0	$0	$0	$0	$0	$0	$0	$24,990
28	PRIOR MONTH TRUE-UP													
29	TOTAL DEPRECIATION & RETURN	$357,944	$355,688	$353,433	$351,177	$239,247	$0	$0	$0	$0	$0	$0	$0	$1,657,489
30														
31	ESTIMATED FUEL SAVINGS	$309,972	$174,435	$573,395	$468,884	$587,882	$0	$0	$0	$0	$0	$0	$0	$2,114,569
32	TOTAL DEPRECIATION & RETURN	$357,944	$355,688	$353,433	$351,177	$239,247	$0	$0	$0	$0	$0	$0	$0	$1,657,489
33	NET BENEFIT (COST) TO RATEPAYER	($47,972)	($181,253)	$219,963	$117,707	$348,635	$0	$0	$0	$0	$0	$0	$0	$457,080

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - DECEMBER USING AN ANNUAL RATE OF 7.7662% (EQUITY 6.0293% , DEBT 1.7369%). RATES ARE BASED ON THE MAY 2019 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 25.345%
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 December 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	83,633	1.39%	7.98%	0.1110%
Total	$ 6,011,707	100.00%		6.23%

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	2,598,065	Equity - Common	54.00%
Total	$ 4,495,662	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	0.0599%
Weighted Cost	0.1110%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	0.0599%
	4.4896%
Times Tax Multiplier	1.34295
Total Equity Component	6.0293%

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	0.0511%
Total Debt Component	1.7369%
	7.7662%

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)

GENERATING PERFORMANCE INCENTIVE FACTOR

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2	Actual Unit Performance Data	43

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 64
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: Brian S. Buckley BSB-1

EXHIBIT NO. ___ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
GPIF 2018 FINAL TRUE-UP
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 20190001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2018 – DECEMBER 2018

TRUE-UP

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2018 - DECEMBER 2018
TRUE-UP
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2018 - DECEMBER 2018

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	29,243.7	9,277.1
+9	26,319.4	8,349.4
+8	23,395.0	7,421.7
+7	20,470.6	6,494.0
+6	17,546.2	5,566.3
+5	14,621.9	4,638.5
+4	11,697.5	3,710.8
+3	8,773.1	2,783.1
+2	5,848.7	1,855.4
+1	2,924.4	927.7
0	0.0	0.0
-1	(3,224.6)	(927.7)
-2	(6,449.2)	(1,855.4)
-3	(9,673.8)	(2,783.1)
-4	(12,898.4)	(3,710.8)
-5	(16,123.0)	(4,638.5)
-6	(19,347.6)	(5,566.3)
-7	(22,572.2)	(6,494.0)
-8	(25,796.8)	(7,421.7)
-9	(29,021.4)	(8,349.4)
-10	(32,246.0)	(9,277.1)

GPI POINTS 4.464

REWARD DOLLARS $4,141,330

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2018 - DECEMBER 2018

Line 1	Beginning of period balance of common equity: End of month common equity:		$	2,586,157,995
Line 2	Month of January	2018	$	2,608,445,827
Line 3	Month of February	2018	$	2,639,830,563
Line 4	Month of March	2018	$	2,651,365,755
Line 5	Month of April	2018	$	2,670,627,705
Line 6	Month of May	2018	$	2,736,677,421
Line 7	Month of June	2018	$	2,767,425,947
Line 8	Month of July	2018	$	2,801,892,170
Line 9	Month of August	2018	$	2,877,297,250
Line 10	Month of September	2018	$	2,912,895,991
Line 11	Month of October	2018	$	2,945,089,060
Line 12	Month of November	2018	$	2,856,484,621
Line 13	Month of December	2018	$	2,867,405,914
Line 14	(Summation of line 1 through line 13 divided by 13)		$	2,763,199,709
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			74.46%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	9,277,090
Line 18	Jurisdictional Sales			19,631,464 MWH
Line 19	Total Sales			19,631,464 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)		$	9,277,090
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-Point level from Sheet No. 3.515)		$	14,621,867
Line 23	**Maximum Allowed GPIF Reward (At 10 GPIF-Point Level; the lesser of line 21 and line 22)**		**$**	**9,277,090**

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2018 - DECEMBER 2018

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
BIG BEND 2	80.9%	EAF	2.11%	10.000	0.211
BIG BEND 3	75.5%	EAF	3.69%	10.000	0.369
BIG BEND 4	69.5%	EAF	5.04%	-10.000	-0.504
POLK 1	69.8%	EAF	0.72%	-9.150	-0.066
POLK 2	90.1%	EAF	4.82%	10.000	0.482
BAYSIDE 1	83.7%	EAF	2.63%	9.183	0.242
BAYSIDE 2	78.0%	EAF	5.15%	3.816	0.196
BIG BEND 2	11,166	ANOHR	2.66%	1.969	0.052
BIG BEND 3	10,841	ANOHR	4.95%	-5.018	-0.249
BIG BEND 4	10,610	ANOHR	7.34%	-2.821	-0.207
POLK 1	10,721	ANOHR	3.52%	-10.000	-0.352
POLK 2	6,800	ANOHR	45.28%	10.000	4.528
BAYSIDE 1	7,455	ANOHR	5.98%	-4.000	-0.239
BAYSIDE 2	7,528	ANOHR	6.11%	0.000	0.000
			100.00%		4.464

GPIF REWARD	**$ 4,141,330**

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 2	2.11%	61.51	68.2	48.1	615.6	(1,077.7)	80.9%	615.6
BIG BEND 3	3.69%	66.72	72.4	55.4	1,079.4	(3,189.4)	75.5%	1,079.4
BIG BEND 4	5.04%	78.68	82.0	72.1	1,473.1	(1,845.8)	69.5%	(1,845.8)
POLK 1	0.72%	74.43	77.0	69.4	211.9	(380.9)	69.8%	(348.5)
POLK 2	4.82%	83.22	85.7	78.2	1,408.9	(1,372.7)	90.1%	1,408.9
BAYSIDE 1	2.63%	82.53	83.8	80.0	770.2	(385.1)	83.7%	707.3
BAYSIDE 2	5.15%	77.34	79.1	73.9	1,505.7	(1,815.5)	78.0%	574.6
GPIF SYSTEM	**24.16%**				**7,064.8**	**(10,067.0)**		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR (Btu/kwh)	TARGET NOF (%)	ANOHR TARGET RANGE MIN.	ANOHR TARGET RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	ACTUAL ADJUSTED ANOHR	EST. FUEL SAVINGS/ LOSS ($000)
BIG BEND 2	2.66%	11,320	60.3	10,843	11,798	778.3	(778.3)	11,166	153.3
BIG BEND 3	4.95%	10,619	80.8	10,252	10,987	1,448.4	(1,448.4)	10,841	(726.9)
BIG BEND 4	7.34%	10,448	86.4	10,066	10,830	2,146.5	(2,146.5)	10,610	(605.6)
POLK 1	3.52%	9,978	99.1	9,644	10,312	1,028.0	(1,028.0)	10,721	(1,028.0)
POLK 2	45.28%	7,382	76.4	6,827	7,936	13,242.8	(13,242.8)	6,800	13,242.8
BAYSIDE 1	5.98%	7,343	62.8	7,176	7,510	1,749.5	(1,749.5)	7,455	(699.8)
BAYSIDE 2	6.11%	7,471	52.3	7,277	7,665	1,785.6	(1,785.6)	7,528	0.0
GPIF SYSTEM	**75.84%**					**22,178.9**	**(22,178.9)**		

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2018 - DECEMBER 2018

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 2	70.0	10.9	80.9
BIG BEND 3	76.5	-1.0	75.5
BIG BEND 4	60.2	9.3	69.5
POLK 1	60.7	9.1	69.8
POLK 2	93.8	-3.7	90.1
BAYSIDE 1	93.0	-9.3	83.7
BAYSIDE 2	77.1	0.9	78.0

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 2	11,522	-356	11,166
BIG BEND 3	11,162	-321	10,841
BIG BEND 4	10,740	-130	10,610
POLK 1	10,373	348	10,721
POLK 2	6,787	13	6,800
BAYSIDE 1	7,473	-18	7,455
BAYSIDE 2	7,537	-9	7,528

(1) Documentation of adjustments to Actual EAF on pages 7 - 13

(2) Documentation of adjustments to Actual ANOHR on pages 14 - 20

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 2
JANUARY 2018 - DECEMBER 2018

WEIGHTING FACTOR = 2.11%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	61.5	70.0	80.9
POH	575.0	1,682.2	575.0
FOH + EFOH	2,670.1	298.0	344.6
MOH + EMOH	126.8	646.9	748.1
POF	6.6	19.2	6.6
EFOF	30.5	3.4	3.9
EMOF	1.4	7.4	8.5
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 575}{8760 - 1682.2} \times (298 + 646.9) = 1{,}092.7$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{1{,}092.7}{8{,}760.0} \times 100 = 80.9$$

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
BIG BEND UNIT NO. 3
JANUARY 2018 - DECEMBER 2018

WEIGHTING FACTOR = 3.69%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	66.7	76.5	75.5
POH	576.0	470.8	576.0
FOH + EFOH	2,206.1	1,235.2	1,219.5
MOH + EMOH	133.4	355.2	350.7
POF	6.6	5.4	6.6
EFOF	25.2	14.1	13.9
EMOF	1.5	4.1	4.0
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 470.8} \times (1235.2 + 355.2) = 1,570.2$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{1,570.2}{8,760.0} \times 100 = 75.5$$

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
BIG BEND UNIT NO. 4
JANUARY 2018 - DECEMBER 2018

WEIGHTING FACTOR = 5.04%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	78.7	60.2	69.5
POH	576.0	1,676.7	576.0
FOH + EFOH	981.1	1,608.9	1,858.9
MOH + EMOH	311.0	201.7	233.0
POF	6.6	19.1	6.6
EFOF	11.2	18.4	21.2
EMOF	3.6	2.3	2.7
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 1676.7} \times (1608.9 + 201.7) = 2{,}092.0$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{2{,}092.0}{8{,}760.0} \times 100 = 69.5$$

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
POLK UNIT NO. 1
JANUARY 2018 - DECEMBER 2018

WEIGHTING FACTOR = 0.72%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	74.4	60.7	69.8
POH	1,512.0	2,460.1	1,512.0
FOH + EFOH	626.8	849.1	976.9
MOH + EMOH	101.4	129.6	149.1
POF	17.3	28.1	17.3
EFOF	7.2	9.7	11.2
EMOF	1.2	1.5	1.7
	-9.150	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1512}{8760 - 2460.1} \times (849.1 + 129.6) = 1{,}126.0$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 17.3 - \frac{1126.0}{8{,}760.0} \times 100 = 69.8$$

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 2018 - DECEMBER 2018

WEIGHTING FACTOR = 4.82%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	83.2	93.8	90.1
POH	505.0	175.3	505.0
FOH + EFOH	521.9	109.3	105.1
MOH + EMOH	442.9	261.3	251.3
POF	5.8	2.0	5.8
EFOF	6.0	1.2	1.2
EMOF	5.1	3.0	2.9
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 505}{8760 - 175.3} \times (109.3 + 261.3) = 356.4$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 5.8 - \frac{356.4}{8,760.0} \times 100 = 90.1$$

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 2018 - DECEMBER 2018

WEIGHTING FACTOR = 2.63%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	82.5	93.0	83.7
POH	1,297.0	468.3	1,297.0
FOH + EFOH	98.7	21.3	19.2
MOH + EMOH	134.6	127.5	114.8
POF	14.8	5.3	14.8
EFOF	1.1	0.2	0.2
EMOF	1.5	1.5	1.3
	9.183	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1297}{8760 - 468.3} \times (21.3 + 127.5) = 133.9$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 14.8 - \frac{133.9}{8,760.0} \times 100 = 83.7$$

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 2018 - DECEMBER 2018

WEIGHTING FACTOR = 5.15%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	77.3	77.1	78.0
POH	1,631.0	1,718.0	1,631.0
FOH + EFOH	179.7	92.5	93.6
MOH + EMOH	174.7	197.5	199.9
POF	18.6	19.6	18.6
EFOF	2.1	1.1	1.1
EMOF	2.0	2.3	2.3
	3.816	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1631}{8760 - 1718} \times (92.5 + 197.5) = 293.6$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 18.6 - \frac{293.6}{8{,}760.0} \times 100 = 78.0$$

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 HEAT RATE
BIG BEND UNIT NO. 2
JANUARY 2018 - DECEMBER 2018

WEIGHTING FACTOR = 2.66%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	11,320	11,522
NET GENERATION (GWH)	418.6	598.8
OPERATING BTU (10^9)	5,010.6	6,898.8
NET OUTPUT FACTOR	60.3	39.7

1.969 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-17.28) + 12362.43 = ANOHR

39.7 * (-17.28) + 12362.43 = 11,677

11,522 - 11,677 = -155

11,320 + -155 = 11,166 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 3
JANUARY 2018 - DECEMBER 2018

WEIGHTING FACTOR = 4.95%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,619	11,162
NET GENERATION (GWH)	1,743.6	1,552.7
OPERATING BTU (10^9)	18,360.1	17,331.6
NET OUTPUT FACTOR	80.8	62.8

-5.018 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-17.83) + 12059.89 = ANOHR

62.8 * (-17.83) + 12059.89 = 10,940

11,162 - 10,940 = 222

10,619 + 222 = 10,841 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 4
JANUARY 2018 - DECEMBER 2018

WEIGHTING FACTOR = 7.34%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,448	10,740
NET GENERATION (GWH)	2,524.3	2,099.1
OPERATING BTU (10^9)	26,288.8	22,545.2
NET OUTPUT FACTOR	86.4	75.9

-2.821 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-12.37) + 11517.84 = ANOHR

75.9 * (-12.37) + 11517.84 = 10,579

10,740 - 10,579 = 161

10,448 + 161 = 10,610 ← 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 2018 - DECEMBER 2018

WEIGHTING FACTOR = 3.52%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	9,978	10,373
NET GENERATION (GWH)	1,453.0	926.4
OPERATING BTU (10^9)	14,699.4	9,609.0
NET OUTPUT FACTOR	99.1	78.1

-10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(16.58) + 8334.23 = ANOHR

78.1 * (16.58) + 8334.23 = 9,629

10,373 - 9,629 = 744

9,978 + 744 = 10,721 ← 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 2018 - DECEMBER 2018

WEIGHTING FACTOR = 45.28%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7,382	6,787
NET GENERATION (GWH)	7,218.8	7,305.6
OPERATING BTU (10^9)	49,307.7	49,582.3
NET OUTPUT FACTOR	76.4	77.3

10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-13.65) + 8424.41 = ANOHR

77.3 * (-13.65) + 8424.41 = 7,369

6,787 - 7,369 = -582

7,382 + -582 = 6,800 ← 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 2018 - DECEMBER 2018

WEIGHTING FACTOR = 5.98%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7,343	7,473
NET GENERATION (GWH)	3,306.0	3,237.8
OPERATING BTU (10^9)	24,502.9	24,195.8
NET OUTPUT FACTOR	62.8	53.9

-4.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-1.98) + 7467.71 = ANOHR

53.9 * (-1.98) + 7467.71 = 7,361

7,473 - 7,361 = 112

7,343 + 112 = 7,455 ← 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 2018 - DECEMBER 2018

WEIGHTING FACTOR = 6.11%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7,471	7,537
NET GENERATION (GWH)	3,017.0	3,377.2
OPERATING BTU (10^9)	23,006.7	25,454.5
NET OUTPUT FACTOR	52.3	50.3

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-4.67) + 7715.3 = ANOHR

50.3 * (-4.67) + 7715.3 = 7,480

7,537 - 7,480 = 57

7,471 + 57 = 7,528 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

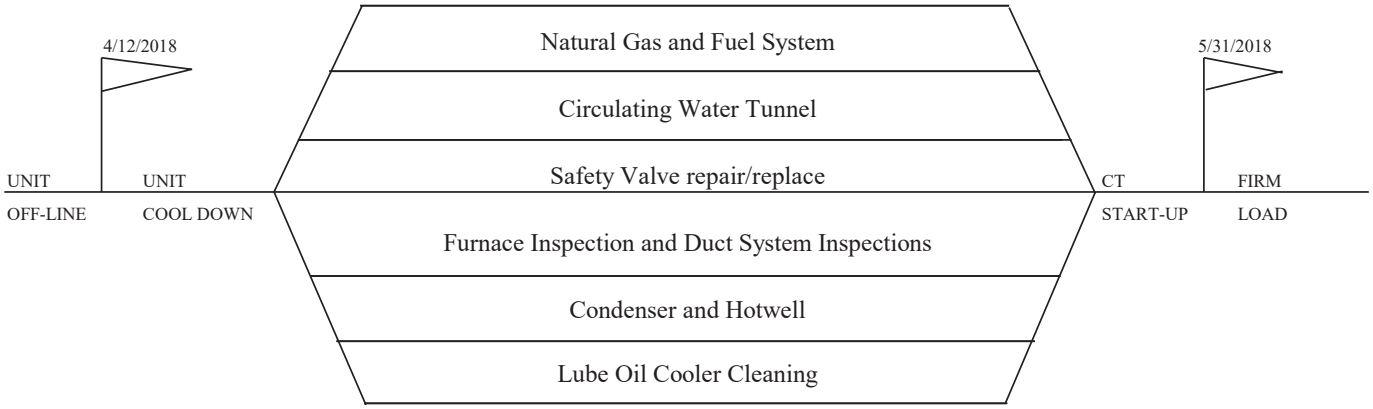
ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2018 - DECEMBER 2018

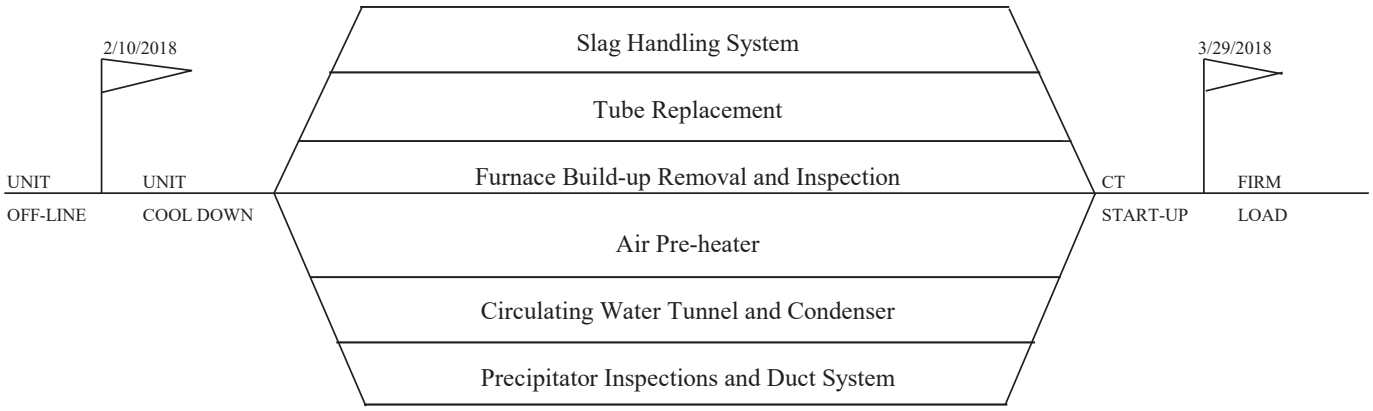
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
+	BIG BEND 2	Apr 12	-	May 31	Safety Valve repair/replace, Lube Oil Cooler Cleaning, Circulating Water Tunnel, Condenser, Furnace Inspection, Duct System Inspections, Hotwell, Natural Gas and Fuel System
		Dec 01	-	Dec 21	Fuel System Cleanup and FGD/SCR work
	BIG BEND 3	Mar 17	-	Apr 05	Fuel System Cleanup and FGD/SCR work
+	BIG BEND 4	Feb 10	-	Mar 29	Furnace Build-up Removal, Furnace Inspection, Tube Replacement, Slag Handling System, Air Pre-heater, Circulating Water Tunnel, Condenser, Precipitator Inspections, and Duct System
		Nov 01	-	Nov 23	Fuel System Cleanup and FGD/SCR work
	POLK 1	Mar 04	-	Mar 10	Fuel System Cleanup
+		Sep 12	-	Dec 21	GTG Rotor Replacement, GTG Electrical Building Replacement, HRSG Harp Replacement, 1A Condenser Cooling Water Motor and Pump, ASU MAC Compressor Rotor Replacement, Generator Protection, HRSG SH and RH Attemperator Loop Replacement
	POLK 2	Feb 05	-	Feb 09	EBI and HRSG Inspections
		Nov 25	-	Nov 29	Fuel System Cleanup
	BAYSIDE 1	Apr 17	-	Apr 30	Fuel System Cleanup
		Oct 07	-	Oct 14	Fuel System Cleanup
		Nov 08	-	Nov 09	Switchyard work
+	BAYSIDE 2	Jan 31	-	Apr 13	HP/IP/LP Turbines, ST Generator, 2A/2B/2C/2D HRSG, ST Governor Valves, ST Throttle / Intercept / Reheat Stop Valves, ST Condenser and Air Removal Pump

+ **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 2018 - DECEMBER 2018

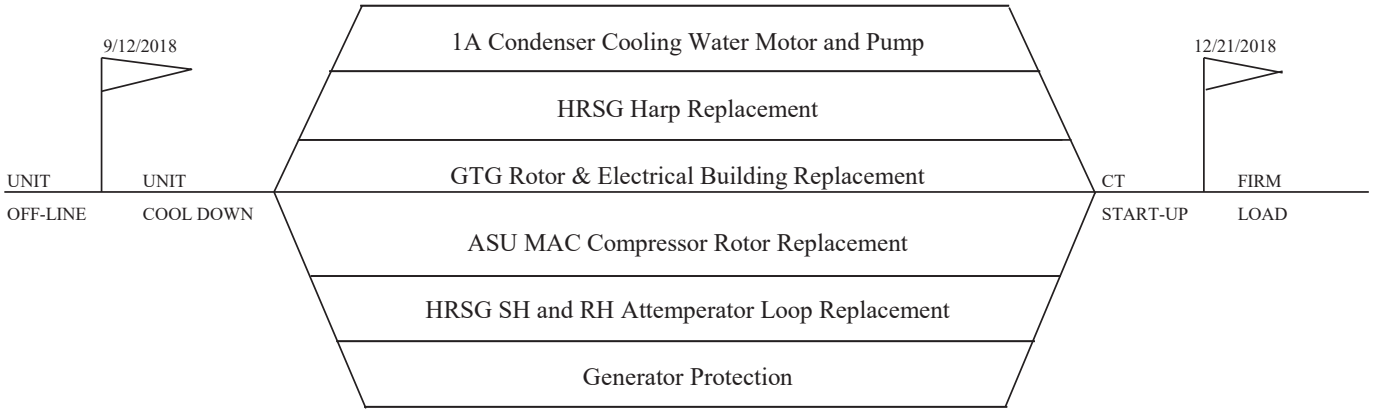


TAMPA ELECTRIC COMPANY
BIG BEND 2
PLANNED OUTAGE 2018
ACTUAL CPM

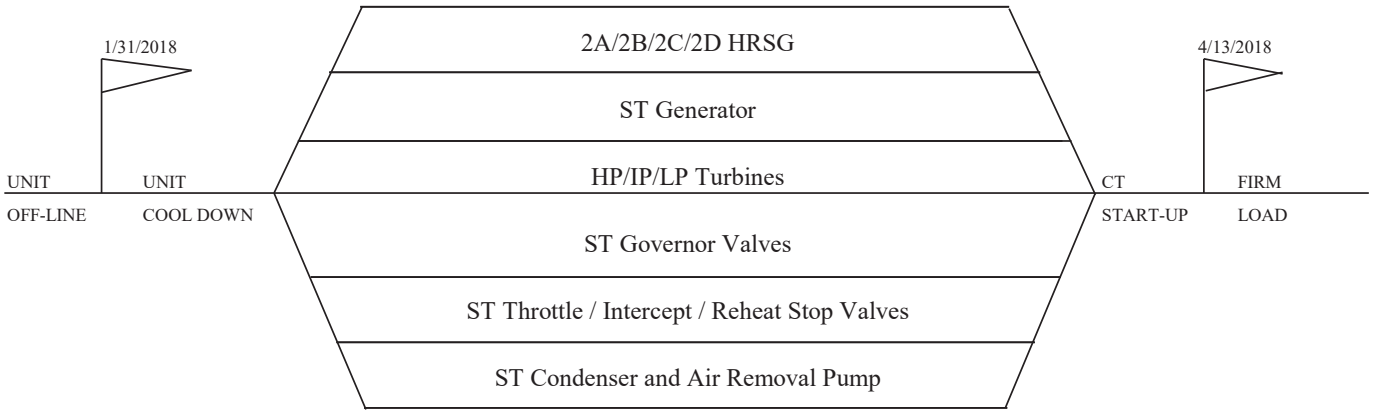


TAMPA ELECTRIC COMPANY
BIG BEND 4
PLANNED OUTAGE 2018
ACTUAL CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2018 - DECEMBER 2018



TAMPA ELECTRIC COMPANY
POLK 1
PLANNED OUTAGE 2018
ACTUAL CPM



TAMPA ELECTRIC COMPANY
BAYSIDE 2
PLANNED OUTAGE 2018
ACTUAL CPM

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2018 - DECEMBER 2018

BIG BEND 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	615.6	68.2	+10	778.3	10,843
+9	554.1	67.6	+9	700.5	10,883
+8	492.5	66.9	+8	622.6	10,923
+7	430.9	66.2	+7	544.8	10,963
+6	369.4	65.5	+6	467.0	11,004
+5	307.8	64.9	+5	389.2	11,044
+4	246.3	64.2	+4	311.3	11,084
+3	184.7	63.5	+3	233.5	11,124
+2	123.1	62.9	+2	155.7	11,165
+1	61.6	62.2	+1	77.8	11,205
					11,245
0	0.0	61.5	0	0.0	11,320
					11,395
-1	(107.8)	60.2	-1	(77.8)	11,436
-2	(215.5)	58.8	-2	(155.7)	11,476
-3	(323.3)	57.5	-3	(233.5)	11,516
-4	(431.1)	56.1	-4	(311.3)	11,556
-5	(538.9)	54.8	-5	(389.2)	11,597
-6	(646.6)	53.5	-6	(467.0)	11,637
-7	(754.4)	52.1	-7	(544.8)	11,677
-8	(862.2)	50.8	-8	(622.6)	11,717
-9	(970.0)	49.4	-9	(700.5)	11,758
-10	(1,077.7)	48.1	-10	(778.3)	11,798

EAF POINTS 10.000

Adjusted EAF 80.9

AHR POINTS 1.969

Adjusted ANOHR 11,166

Weighting Factor = 2.11%

Weighting Factor = 2.66%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2018 - DECEMBER 2018

BIG BEND 3

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	1,079.4	72.4	+10	1,448.4	10,252
+9	971.4	71.8	+9	1,303.5	10,281
+8	863.5	71.3	+8	1,158.7	10,310
+7	755.6	70.7	+7	1,013.9	10,339
+6	647.6	70.1	+6	869.0	10,369
+5	539.7	69.6	+5	724.2	10,398
+4	431.7	69.0	+4	579.4	10,427
+3	323.8	68.4	+3	434.5	10,456
+2	215.9	67.9	+2	289.7	10,486
+1	107.9	67.3	+1	144.8	10,515
					10,544
0	0.0	66.7	0	0.0	10,619
					10,694
-1	(318.9)	65.6	-1	(144.8)	10,723
-2	(637.9)	64.5	-2	(289.7)	10,753
-3	(956.8)	63.3	-3	(434.5)	10,782
-4	(1,275.8)	62.2	-4	(579.4)	10,811
-5	(1,594.7)	61.0	-5	(724.2)	10,840
-6	(1,913.6)	59.9	-6	(869.0)	10,870
-7	(2,232.6)	58.8	-7	(1,013.9)	10,899
-8	(2,551.5)	57.6	-8	(1,158.7)	10,928
-9	(2,870.5)	56.5	-9	(1,303.5)	10,957
-10	(3,189.4)	55.4	-10	(1,448.4)	10,987

EAF POINTS 10.000

Adjusted EAF 75.5

AHR POINTS -5.018

Adjusted ANOHR 10,841

Weighting Factor = 3.69%

Weighting Factor = 4.95%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2018 - DECEMBER 2018

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	1,473.1	82.0	+10	2,146.5	10,066
+9	1,325.8	81.6	+9	1,931.8	10,097
+8	1,178.5	81.3	+8	1,717.2	10,128
+7	1,031.2	81.0	+7	1,502.5	10,159
+6	883.9	80.6	+6	1,287.9	10,189
+5	736.6	80.3	+5	1,073.2	10,220
+4	589.2	80.0	+4	858.6	10,251
+3	441.9	79.7	+3	643.9	10,281
+2	294.6	79.3	+2	429.3	10,312
+1	147.3	79.0	+1	214.6	10,343
					10,373
0	0.0	78.7	0	0.0	10,448
					10,523
-1	(184.6)	78.0	-1	(214.6)	10,554
-2	(369.2)	77.4	-2	(429.3)	10,585
-3	(553.7)	76.7	-3	(643.9)	10,615
-4	(738.3)	76.1	-4	(858.6)	10,646
-5	(922.9)	75.4	-5	(1,073.2)	10,677
-6	(1,107.5)	74.7	-6	(1,287.9)	10,708
-7	(1,292.0)	74.1	-7	(1,502.5)	10,738
-8	(1,476.6)	73.4	-8	(1,717.2)	10,769
-9	(1,661.2)	72.8	-9	(1,931.8)	10,800
-10	(1,845.8)	72.1	-10	(2,146.5)	10,830

EAF POINTS -10.000

Adjusted EAF 69.5

AHR POINTS -2.821

Adjusted ANOHR 10,610

Weighting Factor = 5.04%

Weighting Factor = 7.34%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2018 - DECEMBER 2018

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	211.9	77.0	+10	1,028.0	9,644
+9	190.7	76.7	+9	925.2	9,670
+8	169.6	76.4	+8	822.4	9,696
+7	148.4	76.2	+7	719.6	9,722
+6	127.2	75.9	+6	616.8	9,748
+5	106.0	75.7	+5	514.0	9,774
+4	84.8	75.4	+4	411.2	9,799
+3	63.6	75.2	+3	308.4	9,825
+2	42.4	74.9	+2	205.6	9,851
+1	21.2	74.7	+1	102.8	9,877
					9,903
0	0.0	74.4	0	0.0	9,978
					10,053
-1	(38.1)	73.9	-1	(102.8)	10,079
-2	(76.2)	73.4	-2	(205.6)	10,105
-3	(114.3)	72.9	-3	(308.4)	10,130
-4	(152.4)	72.4	-4	(411.2)	10,156
-5	(190.4)	71.9	-5	(514.0)	10,182
-6	(228.5)	71.4	-6	(616.8)	10,208
-7	(266.6)	70.9	-7	(719.6)	10,234
-8	(304.7)	70.4	-8	(822.4)	10,260
-9	(342.8)	69.9	-9	(925.2)	10,286
-10	(380.9)	69.4	-10	(1,028.0)	10,312

EAF POINTS -9.150 → **Adjusted EAF 69.8**

AHR POINTS -10.000 → **Adjusted ANOHR 10.721**

Weighting Factor = 0.72%

Weighting Factor = 3.52%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2018 - DECEMBER 2018

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	**EAF POINTS 10.000**	1,408.9	**Adjusted EAF 90.1**	85.7	+10	**AHR POINTS 10.000**	13,242.8	**Adjusted ANOHR 6,800**	6,827
+9		1,268.0		85.5	+9		11,918.5		6,875
+8		1,127.1		85.2	+8		10,594.2		6,923
+7		986.2		85.0	+7		9,269.9		6,971
+6		845.3		84.7	+6		7,945.7		7,019
+5		704.4		84.5	+5		6,621.4		7,067
+4		563.5		84.2	+4		5,297.1		7,115
+3		422.7		84.0	+3		3,972.8		7,163
+2		281.8		83.7	+2		2,648.6		7,211
+1		140.9		83.5	+1		1,324.3		7,259
									7,307
0		0.0		83.2	0		0.0		7,382
									7,457
-1		(137.3)		82.7	-1		(1,324.3)		7,505
-2		(274.5)		82.2	-2		(2,648.6)		7,553
-3		(411.8)		81.7	-3		(3,972.8)		7,601
-4		(549.1)		81.2	-4		(5,297.1)		7,648
-5		(686.3)		80.7	-5		(6,621.4)		7,696
-6		(823.6)		80.2	-6		(7,945.7)		7,744
-7		(960.9)		79.7	-7		(9,269.9)		7,792
-8		(1,098.2)		79.2	-8		(10,594.2)		7,840
-9		(1,235.4)		78.7	-9		(11,918.5)		7,888
-10		(1,372.7)		78.2	-10		(13,242.8)		7,936
Weighting Factor =				4.82%	Weighting Factor =				45.28%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2018 - DECEMBER 2018

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	**EAF POINTS 9.183**	770.2	**Adjusted EAF 83.7**	83.8	+10		1,749.5		7,176
+9		693.2		83.7	+9		1,574.5		7,186
+8		616.2		83.5	+8		1,399.6		7,195
+7		539.1		83.4	+7		1,224.6		7,204
+6		462.1		83.3	+6		1,049.7		7,213
+5		385.1		83.2	+5		874.7		7,222
+4		308.1		83.0	+4		699.8		7,232
+3		231.1		82.9	+3		524.8		7,241
+2		154.0		82.8	+2		349.9		7,250
+1		77.0		82.7	+1		174.9		7,259
									7,268
0		0.0		82.5	0		0.0		7,343
									7,418
-1		(38.5)		82.3	-1		(174.9)		7,427
-2		(77.0)		82.0	-2		(349.9)		7,437
-3		(115.5)		81.8	-3		(524.8)		7,446
-4		(154.0)		81.5	-4	**AHR POINTS -4.000**	(699.8)	**Adjusted ANOHR 7,455**	7,455
-5		(192.5)		81.3	-5		(874.7)		7,464
-6		(231.1)		81.0	-6		(1,049.7)		7,473
-7		(269.6)		80.7	-7		(1,224.6)		7,483
-8		(308.1)		80.5	-8		(1,399.6)		7,492
-9		(346.6)		80.2	-9		(1,574.5)		7,501
-10		(385.1)		80.0	-10		(1,749.5)		7,510

Weighting Factor = 2.63%

Weighting Factor = 5.98%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2018 - DECEMBER 2018

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	1,505.7	79.1	+10	1,785.6	7,277
+9	1,355.1	78.9	+9	1,607.0	7,289
+8	1,204.6	78.7	+8	1,428.4	7,301
+7	1,054.0	78.6	+7	1,249.9	7,313
+6	903.4	78.4	+6	1,071.3	7,324
+5	752.9	78.2	+5	892.8	7,336
+4	602.3	78.0	+4	714.2	7,348
+3	451.7	77.9	+3	535.7	7,360
+2	301.1	77.7	+2	357.1	7,372
+1	150.6	77.5	+1	178.6	7,384
					7,396
0	0.0	77.3	0	0.0	7,471
					7,546
-1	(181.5)	77.0	-1	(178.6)	7,558
-2	(363.1)	76.6	-2	(357.1)	7,570
-3	(544.6)	76.3	-3	(535.7)	7,582
-4	(726.2)	75.9	-4	(714.2)	7,593
-5	(907.7)	75.6	-5	(892.8)	7,605
-6	(1,089.3)	75.3	-6	(1,071.3)	7,617
-7	(1,270.8)	74.9	-7	(1,249.9)	7,629
-8	(1,452.4)	74.6	-8	(1,428.4)	7,641
-9	(1,633.9)	74.2	-9	(1,607.0)	7,653
-10	(1,815.5)	73.9	-10	(1,785.6)	7,665

EAF POINTS 3.816 ← | → **Adjusted EAF 78.0**

← **AHR POINTS 0.000** | → **Adjusted ANOHR 7,528**

Weighting Factor = 5.15%

Weighting Factor = 6.11%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 18 - DEC 18 POF	TARGET PERIOD JAN 18 - DEC 18 EUOF	TARGET PERIOD JAN 18 - DEC 18 EUOR	ACTUAL PERFORMANCE JAN 18 - DEC 18 POF	ACTUAL PERFORMANCE JAN 18 - DEC 18 EUOF	ACTUAL PERFORMANCE JAN 18 - DEC 18 EUOR
BIG BEND 2	2.11%	8.7%	6.6	7.3	7.8	19.2	10.8	13.4
BIG BEND 3	3.69%	15.3%	6.6	31.9	34.2	5.4	18.2	19.2
BIG BEND 4	5.04%	20.9%	6.6	26.7	28.6	19.1	20.7	25.6
POLK 1	0.72%	3.0%	17.3	14.7	17.8	28.1	11.2	15.5
POLK 2	4.82%	19.9%	5.8	8.3	8.8	2.0	4.2	4.3
BAYSIDE 1	2.63%	10.9%	14.8	11.0	12.9	5.3	1.7	1.8
BAYSIDE 2	5.15%	21.3%	18.6	2.7	3.3	19.6	3.3	4.1
GPIF SYSTEM	**24.2%**	**100.0%**	**10.2**	**15.0**	**16.3**	**12.5**	**10.1**	**11.8**

GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%) **74.9** **77.4**

3 PERIOD AVERAGE POF	3 PERIOD AVERAGE EUOF	3 PERIOD AVERAGE EUOR	3 PERIOD AVERAGE EAF
9.8	**17.3**	**19.0**	**72.9**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 18 - DEC 18	ADJUSTED ACTUAL HEAT RATE JAN 18 - DEC 18
BIG BEND 2	2.66%	3.5%	11,320	11,166
BIG BEND 3	4.95%	6.5%	10,619	10,841
BIG BEND 4	7.34%	9.7%	10,448	10,610
POLK 1	3.52%	4.6%	9,978	10,721
POLK 2	45.28%	59.7%	7,382	6,800
BAYSIDE 1	5.98%	7.9%	7,343	7,455
BAYSIDE 2	6.11%	8.1%	7,471	7,528
GPIF SYSTEM	**75.8%**	**100.0%**		

GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh) **8,153** **7,878**

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2018 - DECEMBER 2018

Points are calculated according to the formula:

$$GPIP = \sum_{i=1}^{n} \left[a_i \left(EAP_i \right) + e_i \left(AHRP_i \right) \right]$$

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.

GPIP =	2.11%	*	(BB 2 EAP)	+	3.69%	*	(BB 3 EAP)	+	5.04%	*	(BB 4 EAP)
+	0.72%	*	(PK 1 EAP)	+	4.82%	*	(PK 2 EAP)	+	2.63%	*	(BAY 1 EAP)
+	5.15%	*	(BAY 2 EAP)	+	2.66%	*	(BB 2 AHRP)	+	4.95%	*	(BB 3 AHRP)
+	7.34%	*	(BB 4 AHRP)	+	3.52%	*	(PK 1 AHRP)	+	45.28%	*	(PK 2 AHRP)
+	5.98%	*	(BAY 1 AHRP)	+	6.11%	*	(BAY 2 AHRP)				

GPIP =	2.11%	*	10.000	+	3.69%	*	10.000	+	5.04%	*	-10.000
+	0.72%	*	-9.150	+	4.82%	*	10.000	+	2.63%	*	9.183
+	5.15%	*	3.816	+	2.66%	*	1.969	+	4.95%	*	-5.018
+	7.34%	*	-2.821	+	3.52%	*	-10.000	+	45.28%	*	10.000
+	5.98%	*	-4.000	+	6.11%	*	0.000				

GPIP =	0.211	+	0.369	+	-0.504
+	-0.066	+	0.482	+	0.242
+	0.196	+	0.052	+	-0.249
+	-0.207	+	-0.352	+	4.528
+	-0.239	+	0.000		

GPIP = 4.464 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 = $4,141,330

EXHIBIT NO. ___ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
GPIF 2018 FINAL TRUE-UP
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 20190001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2018 – DECEMBER 2018

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

ORIGINAL SHEET NO. 8.401.18A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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
BIG BEND 2	JAN 18	FEB 18	MAR 18	APR 18	MAY 18	JUN 18	JUL 18	AUG 18	SEP 18	OCT 18	NOV 18	DEC 18	2018
1. EAF (%)	63.7	66.6	80.1	33.5	0.3	92.5	90.1	89.1	98.3	100.0	99.9	33.9	70.0
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	503.5	549.5	743.0	271.0	0.0	224.3	150.6	356.0	720.0	475.9	211.8	0.0	4,205.7
4. RSH	180.2	36.8	0.0	0.0	2.3	442.7	519.7	313.0	0.0	268.1	509.2	252.4	2,524.4
5. UH	60.3	85.7	0.0	449.0	741.7	53.0	73.6	75.0	0.0	0.0	0.0	491.6	2,029.9
6. POH	0.0	0.0	0.0	449.0	741.7	0.0	0.0	0.0	0.0	0.0	0.0	491.6	1,682.2
7. FOH	60.3	85.7	0.0	0.0	0.0	53.0	34.3	0.0	0.0	0.0	0.0	0.0	233.3
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	39.3	75.0	0.0	0.0	0.0	0.0	114.3
9. PFOH	327.6	235.1	0.0	0.0	0.0	0.0	0.0	11.6	39.4	19.4	47.9	0.0	680.9
10. LR PF (MW)	44.1	9.6	0.0	0.0	0.0	0.0	0.0	175.0	104.3	5.0	5.0	0.0	34.0
11. PMOH	744.0	672.3	743.5	720.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	2,880.8
12. LR PM (MW)	91.9	78.1	78.4	15.9	0.0	235.0	0.0	0.0	0.0	0.0	0.0	0.0	66.3
13. NSC (MW)	395.0	395.0	395.0	385.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	350.0	358.3
14. OPR BTU(GBTU)	732.3	1,006.9	1,196.1	500.0	0.0	306.2	224.0	587.9	1,240.2	757.6	347.6	0.0	6,898.8
15. NET GEN (MWH)	62,029	94,369	105,001	48,780	0	26,562	19,643	47,786	102,138	61,799	30,668	0	598,775
16. ANOHR (BTU/KWH)	11,805.8	10,669.7	11,390.8	10,250.7	0.0	11,529.1	11,405.6	12,302.6	12,142.0	12,259.9	11,333.3	0.0	11,522.0
17. NOF (%)	31.2	43.5	35.8	46.8	0.0	34.8	38.3	39.5	41.7	38.2	42.6	0.0	39.7
18. NPC (MW)	395.0	395.0	395.0	385.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	350.0	358.3
19. ANOHR EQUATION	ANOHR = NOF (-17.276) + 12,362												

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TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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
BIG BEND 3	JAN 18	FEB 18	MAR 18	APR 18	MAY 18	JUN 18	JUL 18	AUG 18	SEP 18	OCT 18	NOV 18	DEC 18	2018
1. EAF (%)	57.3	35.3	30.7	66.2	91.3	95.6	95.7	94.3	68.0	90.4	99.5	93.3	76.5
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	492.1	390.2	384.5	540.9	679.6	691.9	664.0	741.1	506.2	546.3	721.0	215.6	6,573.4
4. RSH	0.0	23.6	0.0	0.0	0.0	28.1	50.1	0.0	0.0	133.7	0.0	478.4	713.8
5. UH	251.9	258.2	358.5	179.1	64.4	0.0	29.9	2.9	213.8	64.0	0.0	50.0	1,472.7
6. POH	0.0	0.0	358.5	112.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	470.8
7. FOH	251.9	258.2	0.0	0.0	64.4	0.0	0.8	2.9	72.0	0.0	0.0	0.0	650.1
8. MOH	0.0	0.0	0.0	66.8	0.0	0.0	29.2	0.0	141.9	64.0	0.0	50.0	351.8
9. PFOH	787.0	672.0	743.0	645.0	1.7	264.4	57.2	141.1	55.5	22.1	50.8	0.0	3,439.8
10. LR PF (MW)	33.4	105.2	84.2	38.8	40.0	46.4	0.0	96.9	101.9	110.9	23.6	0.0	63.9
11. PMOH	0.0	0.0	0.0	2.0	0.0	2.4	2.7	0.0	0.7	0.0	0.0	0.0	7.7
12. LR PM (MW)	0.0	0.0	0.0	120.0	0.0	120.0	240.0	0.0	165.0	0.0	0.0	0.0	165.3
13. NSC (MW)	400.0	400.0	400.0	395.0	395.0	395.0	345.0	345.0	345.0	345.0	345.0	400.0	375.8
14. OPR BTU(GBTU)	1,798.8	987.6	1,084.1	1,965.3	2,635.8	2,359.6	991.3	1,213.2	903.2	1,186.3	1,708.9	497.5	17,331.6
15. NET GEN (MWH)	163,854	85,845	90,768	181,082	247,448	219,091	87,639	100,627	77,828	106,431	149,843	42,260	1,552,716
16. ANOHR BTU/KWH	10,978.0	11,504.3	11,943.4	10,852.9	10,652.0	10,770.0	11,311.7	12,056.4	11,605.2	11,146.3	11,404.9	11,771.2	11,162.0
17. NOF (%)	83.2	55.0	59.0	84.8	92.2	80.2	38.3	39.4	44.6	56.5	60.2	49.0	62.8
18. NPC (MW)	400.0	400.0	400.0	395.0	395.0	395.0	345.0	345.0	345.0	345.0	345.0	400.0	375.8
19. ANOHR EQUATION	ANOHR = NOF (-17.826) + 12,060												

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TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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
BIG BEND 4	JAN 18	FEB 18	MAR 18	APR 18	MAY 18	JUN 18	JUL 18	AUG 18	SEP 18	OCT 18	NOV 18	DEC 18	2018
1. EAF (%)	78.7	13.1	8.0	87.7	68.2	60.1	80.3	78.5	78.7	81.0	18.5	65.0	60.2
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	744.0	69.0	59.2	720.0	635.9	523.4	744.0	744.0	720.0	610.5	165.1	571.2	6,306.3
4. RSH	0.0	147.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	133.5	7.0	0.0	287.6
5. UH	0.0	456.0	683.8	0.0	108.1	196.6	0.0	0.0	0.0	0.0	548.9	172.8	2,166.1
6. POH	0.0	456.0	683.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	537.0	0.0	1,676.7
7. FOH	0.0	0.0	0.0	0.0	108.1	196.6	0.0	0.0	0.0	0.0	11.9	1.9	318.5
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	170.9	170.9
9. PFOH	1,611.4	672.0	743.0	762.4	2,361.8	1,557.0	744.0	744.0	720.0	744.0	721.0	744.0	12,124.6
10. LR PF (MW)	43.4	84.2	0.0	49.9	23.3	25.0	81.8	93.9	82.0	83.2	23.6	52.2	46.7
11. PMOH	0.0	0.0	0.0	6.3	5.9	5.0	16.4	0.0	34.6	0.0	0.0	0.0	68.4
12. LR PM (MW)	0.0	0.0	0.0	119.5	171.1	113.8	199.1	0.0	228.1	0.0	0.0	0.0	197.7
13. NSC (MW)	442.0	442.0	442.0	437.0	437.0	437.0	437.0	437.0	437.0	437.0	437.0	442.0	438.7
14. OPR BTU(GBTU)	2,713.8	129.7	163.7	2,755.0	2,397.7	1,977.7	2,766.9	2,680.4	2,547.9	1,854.2	542.7	2,015.5	22,545.2
15. NET GEN (MWH)	254,243	13,470	15,848	260,531	213,939	181,524	249,646	247,319	238,823	192,564	46,324	184,874	2,099,105
16. ANOHR BTU/KWH	10,674.2	9,626.0	10,330.3	10,574.6	11,207.5	10,894.9	11,083.2	10,837.9	10,668.8	9,628.8	11,716.1	10,901.8	10,740.0
17. NOF (%)	77.3	44.2	60.5	82.8	77.0	79.4	76.8	76.1	75.9	72.2	64.2	73.2	75.9
18. NPC (MW)	442.0	442.0	442.0	437.0	437.0	437.0	437.0	437.0	437.0	437.0	437.0	442.0	438.7
19. ANOHR EQUATION	ANOHR = NOF (-12.371) + 11,518												

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TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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
POLK 1	JAN 18	FEB 18	MAR 18	APR 18	MAY 18	JUN 18	JUL 18	AUG 18	SEP 18	OCT 18	NOV 18	DEC 18	2018
1. EAF (%)	75.1	97.1	49.1	72.8	82.9	89.6	89.1	97.1	46.3	0.0	0.0	31.4	60.7
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	567.8	669.2	384.2	454.4	648.7	603.2	708.1	740.3	363.2	0.0	0.0	8.1	5,147.0
4. RSH	0.0	0.0	12.6	136.7	47.5	108.8	0.0	0.0	0.0	0.0	0.0	225.8	531.4
5. UH	176.2	2.8	346.2	129.0	47.8	8.0	35.9	3.8	356.8	744.0	721.0	510.1	3,081.6
6. POH	0.0	0.0	147.2	0.0	0.0	0.0	0.0	0.0	356.8	744.0	721.0	491.0	2,460.1
7. FOH	176.2	2.8	199.0	95.3	3.3	8.0	35.9	3.8	0.0	0.0	0.0	6.3	530.6
8. MOH	0.0	0.0	0.0	33.6	44.5	0.0	0.0	0.0	0.0	0.0	0.0	12.9	91.0
9. PFOH	236.6	121.2	171.5	720.0	744.0	577.2	239.6	100.9	3.3	0.0	0.0	0.0	2,914.3
10. LR PF (MW)	8.2	29.8	30.0	20.5	23.4	25.6	46.4	44.0	70.0	0.0	0.0	0.0	25.2
11. PMOH	0.0	0.0	420.7	0.0	0.0	0.0	0.0	0.0	497.5	744.0	721.0	0.0	2,383.2
12. LR PM (MW)	0.0	0.0	4.4	0.0	0.0	0.0	0.0	0.0	14.1	0.0	0.0	0.0	3.7
13. NSC (MW)	220.0	220.0	220.0	220.0	220.0	220.0	245.0	245.0	245.0	245.0	245.0	220.0	230.4
14. OPR BTU(GBTU)	1,332.2	1,559.7	703.8	552.9	630.0	969.9	1,435.1	1,760.6	652.6	0.0	0.0	12.3	9,609.0
15. NET GEN (MWH)	126,117	152,887	69,570	60,461	67,992	79,644	141,705	167,216	68,117	-2,588	-2,515	-2,225	926,381
16. ANOHR BTU/KWH	10,563.2	10,201.9	10,116.2	9,144.7	9,265.3	12,178.0	10,127.1	10,528.8	9,580.3	0.0	0.0	0.0	10,373.0
17. NOF (%)	101.0	103.9	82.3	60.5	47.6	60.0	81.7	92.2	76.6	0.0	0.0	0.0	78.1
18. NPC (MW)	220.0	220.0	220.0	220.0	220.0	220.0	245.0	245.0	245.0	245.0	245.0	220.0	230.4
19. ANOHR EQUATION	ANOHR = NOF (16.584) + 8,334												

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ACTUAL UNIT PERFORMANCE DATA

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POLK 2 CC	JAN 18	FEB 18	MAR 18	APR 18	MAY 18	JUN 18	JUL 18	AUG 18	SEP 18	OCT 18	NOV 18	DEC 18	2018
1. EAF (%)	89.0	88.1	97.1	98.9	88.6	99.9	99.8	99.7	98.4	94.9	88.9	83.1	93.8
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	743.0	672.0	743.0	720.0	656.7	720.0	744.0	741.0	712.0	702.0	712.0	667.4	8,533.1
4. RSH	44.6	29.5	6.8	35.7	105.1	15.8	13.5	30.9	22.5	19.1	36.7	0.0	360.1
5. UH	42.5	47.3	10.6	4.4	79.9	0.0	0.0	1.7	7.0	22.3	72.0	76.6	364.3
6. POH	20.6	47.3	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.0	29.8	175.3
7. FOH	11.8	0.0	5.1	4.4	6.0	0.0	0.0	0.5	6.4	0.5	0.0	5.8	40.4
8. MOH	10.1	0.0	0.0	0.0	73.9	0.0	0.0	1.2	0.7	21.8	0.0	41.0	148.6
9. PFOH	656.7	0.9	91.8	30.4	6.2	6.1	6.0	4.9	44.5	5.1	0.0	267.5	1,120.1
10. LR PF (MW)	33.9	125.0	95.2	115.0	108.9	42.9	235.0	106.0	115.0	106.0	0.0	123.8	68.1
11. PMOH	204.7	315.3	37.3	0.0	49.5	5.8	0.0	0.0	0.0	154.1	244.4	215.0	1,226.0
12. LR PM (MW)	123.0	125.0	125.0	0.0	95.5	115.0	0.0	0.0	0.0	106.0	33.9	118.6	101.8
13. NSC (MW)	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
14. OPR BTU(GBTU)	4,009.6	3,482.9	4,694.6	4,117.4	3,268.6	4,321.1	4,692.8	4,404.3	4,397.2	4,430.9	3,924.8	3,838.1	49,582.3
15. NET GEN (MWH)	586,465	538,133	728,981	634,576	473,543	648,403	674,389	634,827	624,890	638,721	571,331	551,368	7,305,628
16. ANOHR BTU/KWH	6,836.9	6,472.2	6,439.9	6,488.5	6,902.4	6,664.2	6,958.6	6,937.8	7,036.8	6,937.2	6,869.6	6,961.1	6,787.0
17. NOF (%)	65.8	66.7	81.8	83.1	68.0	84.9	85.4	80.7	82.7	85.8	75.6	68.8	77.3
18. NPC (MW)	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
19. ANOHR EQUATION	ANOHR = NOF (-13.653) + 8,424												

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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 UNIT 1	JAN 18	FEB 18	MAR 18	APR 18	MAY 18	JUN 18	JUL 18	AUG 18	SEP 18	OCT 18	NOV 18	DEC 18	2018
1. EAF (%)	96.9	99.7	97.8	57.2	99.2	100.0	100.0	97.5	99.9	77.9	90.3	98.8	93.0
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	670.6	672.0	743.0	422.0	744.0	720.0	744.0	734.0	720.0	582.0	711.2	743.8	8,206.6
4. RSH	58.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58.5
5. UH	15.0	0.0	8.3	298.4	0.0	0.0	0.0	10.2	0.0	161.6	9.8	0.1	503.4
6. POH	0.0	0.0	0.0	298.4	0.0	0.0	0.0	0.0	0.0	160.1	9.8	0.0	468.3
7. FOH	0.0	0.0	8.3	0.0	0.0	0.0	0.0	1.6	0.0	1.5	0.0	0.1	11.6
8. MOH	15.0	0.0	0.0	0.0	0.0	0.0	0.0	8.5	0.0	0.0	0.0	0.0	23.5
9. PFOH	39.6	10.0	19.4	10.3	9.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	88.5
10. LR PF (MW)	82.0	82.0	82.0	79.0	69.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.3
11. PMOH	39.9	9.9	55.6	48.8	45.0	0.0	0.0	75.6	7.7	23.3	444.4	88.8	839.1
12. LR PM (MW)	82.0	82.0	82.0	128.2	79.0	0.0	0.0	79.0	79.0	79.0	94.8	79.0	90.6
13. NSC (MW)	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
14. OPR BTU(GBTU)	1,633.1	2,454.5	2,329.3	1,223.3	2,130.9	2,323.1	2,271.0	2,085.0	2,209.4	1,653.4	1,888.4	1,994.5	24,195.8
15. NET GEN (MWH)	217,843	332,848	308,710	162,902	285,477	306,014	307,294	281,179	295,733	217,768	255,869	266,201	3,237,839
16. ANOHR (BTU/KWH)	7,496.7	7,374.3	7,545.2	7,509.3	7,464.4	7,591.4	7,390.3	7,415.1	7,471.0	7,592.3	7,380.3	7,492.5	7,473.0
17. NOF (%)	41.0	62.5	52.5	55.1	54.7	60.6	58.9	54.6	58.6	53.4	51.3	45.2	53.9
18. NPC (MW)	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
19. ANOHR EQUATION	ANOHR = NOF (-1.982) + 7,468												

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2018 - DECEMBER 2018

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 UNIT 2	JAN 18	FEB 18	MAR 18	APR 18	MAY 18	JUN 18	JUL 18	AUG 18	SEP 18	OCT 18	NOV 18	DEC 18	2018
1. EAF (%)	89.7	0.0	0.0	55.2	93.9	97.0	97.5	97.1	97.6	98.2	92.1	99.6	77.1
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	695.6	0.0	0.0	405.0	708.2	720.0	743.0	736.0	720.0	744.0	721.0	744.0	6,936.8
4. RSH	0.0	0.0	0.0	12.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.8
5. UH	58.1	672.0	743.0	317.4	40.8	0.0	1.0	7.5	0.0	0.0	1.2	0.0	1,841.0
6. POH	12.6	672.0	743.0	290.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,718.0
7. FOH	45.5	0.0	0.0	27.0	0.0	0.0	1.0	7.5	0.0	0.0	1.2	0.0	82.3
8. MOH	0.0	0.0	0.0	0.0	40.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.8
9. PFOH	9.4	0.0	0.0	65.5	51.0	0.0	3.8	0.9	0.0	0.0	0.0	0.0	130.5
10. LR PF (MW)	79.0	0.0	0.0	74.3	77.0	0.0	77.0	77.0	0.0	0.0	0.0	0.0	75.8
11. PMOH	231.8	0.0	0.0	3.5	8.3	272.0	475.6	176.2	210.8	171.3	355.7	35.4	1,940.5
12. LR PM (MW)	79.3	0.0	0.0	77.0	77.0	72.7	34.2	75.5	77.0	73.0	145.3	77.0	78.2
13. NSC (MW)	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
14. OPR BTU(GBTU)	1,818.4	0.0	0.0	1,418.1	2,605.3	2,515.6	2,584.8	2,907.2	2,938.9	3,123.1	2,635.4	2,907.9	25,454.5
15. NET GEN (MWH)	232,588	-3,128	-3,411	187,162	347,726	330,641	349,617	392,400	394,088	412,229	348,754	388,516	3,377,182
16. ANOHR (BTU/KWH)	7,818.0	0.0	0.0	7,576.8	7,492.3	7,608.2	7,393.2	7,408.7	7,457.4	7,576.0	7,556.6	7,484.6	7,537.0
17. NOF (%)	31.9	0.0	0.0	49.7	52.9	49.4	50.7	57.4	58.9	59.6	52.1	49.9	50.3
18. NPC (MW)	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
19. ANOHR EQUATION	ANOHR = NOF (-4.675) + 7,715												

Tampa Electric
2018 Hedging Activity True-up

Tampa Electric's Risk Management Plan identified the following objectives:

- Qualitative Objectives
  Tampa Electric's primary goal in managing risk associated with fuel or power purchases focuses on minimizing supply risk to ensure reliability of electric service to its customers at a reasonable price. To the extent that price risk can be mitigated without compromising supply reliability or imposing unreasonable costs on its customers, Tampa Electric is committed to executing strategies to accomplish its risk management goal.

- 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.

2018 Risk Management Activities
The company's activities in 2018 that supported the objectives listed above are described in the following section.

- Coal Purchases
  Tampa Electric maintains a portfolio of short-term (also called spot market), medium-term and long-term coal contracts and inventory with the goal of minimizing fuel costs and price risk while maintaining reliability of supply. The company procured its 2018 coal needs from suppliers with known, established pricing. Thus, the cost for the commodity was known. Tampa Electric continued to monitor deliveries and volume commitments in contracts as the pricing in the coal market changed. Tampa Electric takes advantage of favorable spot market pricing when the coal supply is needed. Coal was used to produce approximately 18 percent of the electricity the company generated in 2018.

- Coal Risk Management Activities
  Tampa Electric's long-established policy of using physical hedges within its portfolio of different term coal supply contracts continued to help protect ratepayers from coal price volatility.

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PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: J. Brent Caldwell JBC-1

- Natural Gas Purchases

  In 2018, approximately 82 percent of the electricity Tampa Electric generated was produced using natural gas. Tampa Electric's risk management strategy focuses on supply reliability. The components critical to the success of the natural gas purchasing strategy are as follows:

  - Maintaining liquidity by contracting with numerous qualified counterparties;
  - Maintaining physical natural gas storage capacity near Mobile Bay, Alabama;
  - Diversifying interstate pipeline receipt points;
  - Expanding access to additional interstate pipelines;
  - Maintaining databases and reports to monitor activity;
  - Maintaining coordination between power plant operations and natural gas scheduling;
  - Maintaining separation of duties and installation of controls consistent with current industry practices.

- Natural Gas Risk Management Activities

  Natural gas prices historically have been more volatile than coal prices. Natural gas prices are more volatile due to the significant variations in natural gas consumption by natural gas fired power plants that increase and decrease generation to follow changes in demand. Additionally, hurricane activity and other weather-related production reductions or demand increases have a significant impact on the natural gas market.

  As approved by the Commission in prior years' Risk Management Plans, Tampa Electric used financial floating-price-to-fixed-price swaps to hedge natural gas prices for a portion of its expected gas consumption until the hedging moratorium approved by the Commission in Order No. PSC-16-0547-FOF-EI. The company had hedges that were entered prior to the moratorium and settled during 2018. The costs associated with floating-price-to-fixed-price swaps are embedded in the price of the instruments and are included in the fuel commodity costs reported by the company. These hedges are described in the following table.

Tampa Electric
Natural Gas Hedging Activities
January 1, 2018 through December 31, 2018

	Type of Hedge	Settlement Saving/(Loss)	Hedged Volume (MMBTU)	Consumption (MMBTU)	Percent Hedged	Budget Price	Hedge Price	Settle Price
Jan-18	Swaps	($268,000)		8,829,903				$2.738
Feb-18	Swaps	$310,180		8,618,729				$3.631
Mar-18	Swaps	($314,780)		9,138,801				$2.639
Apr-18	Swaps	($125,945)		8,326,287				$2.691
May-18	Swaps	$15,360		8,901,622				$2.821
Jun-18	Swaps	($600)		11,427,304				$2.875
Jul-18	Swaps	$45,440		12,097,762				$2.996
Aug-18	Swaps	$18,990		12,278,919				$2.822
Sep-18	Swaps	$14,290		12,514,965				$2.895
Oct-18	Swaps	$37,560		11,991,072				$3.021
Nov-18	Swaps	$73,250		10,948,303				$3.185
Dec-18	Swaps	$0		N/A				N/A
Total		($232,235)		115,073,667				

For 2018, the calendar year net position for natural gas hedges was higher than the closing price of natural gas, resulting in settlement loss of $232,235. Natural gas price volatility increased in 2018 due primarily to reduced drilling caused by lower prices, increased demand from new liquified natural gas facilities, and low natural gas storage levels.

Tampa Electric increased and diversified its natural gas storage capacity between two storage facilities totaling 2,000,000 MMBtu to enhance its physical reliability of gas supply. The storage provides Tampa Electric with improved access to “intraday” natural gas when an operational need arises, provides improved hurricane coverage, and can be used to cost-effectively manage swings in gas supply needs during extreme weather conditions, weekends, holidays and unplanned power plant outages.

Tampa Electric also continues to improve its physical access to natural gas supply by diversifying its receipt points along the Gulf Coast and other areas when opportunities arise.

In summary, financial hedging activities for natural gas resulted in net settlement loss of $232,235 in 2018; more importantly, Tampa Electric was successful in reducing price uncertainty and maintaining fuel supply reliability for customers through its physical and financial fuel risk management activities.

2018 Market Pricing

Tampa Electric provides a comparison of 2018 fuel prices to the market price for the respective commodity in the following section.

- Coal

  Coal is a commodity with a great range of quality characteristics. Market indexes provide a guide to current market pricing but are not always specific enough to accurately demonstrate the market price of a particular coal. Market prices for coal are most accurately determined by competitive bid solicitations that specify the required coal quality or characteristics. With the exception of purchases for reliability reasons, short-term purchases for changing plant operation needs and spot market purchases to take advantage of favorable pricing, Tampa Electric purchases coal at prices determined by competitive bid solicitations; therefore, the company's purchases are at market. A comparison of coal contract prices for 2018 to the average acceptable bid price or index price is provided in the following table. Unless otherwise stated, the prices represent the market at the time each contract was entered into and are not representative of today's market. Any comparison to current market prices overlooks the market conditions that existed at the time the coal was procured.

Tampa Electric
Coal Contract to Market Indicator Price Comparisons

Supplier	Contract ($/MMBtu)	Market Indicator ($/MMBtu)	Difference ($/MMBtu)	Market Indicator Source	Note
Knight Hawk Coal LLC	[redacted]	$3.39	[redacted]	Gen 2014-01 (RFP issued 11/5/13)	1
Alliance Coal LLC.	[redacted]	$3.39	[redacted]	Gen 2014-01 (RFP issued 11/5/13)	1
Valero Marketing and Supply Company	[redacted]	$3.09	[redacted]	Gen 2018-PC (RFP issued 10/17/17)	2
Koch Carbon	[redacted]	$2.89	[redacted]	Gen 2018-PC (RFP issued 10/17/17)	3
Trafigura AG Branch Office Stamford	[redacted]	$3.24	[redacted]	Sale/Purchase buyback for cost mitigation	4
CMC - Coal Marketing Company LTD.	[redacted]	$3.82	[redacted]	Gen-2018-SALS (RFP issued 10.19.17)	1
Western Kentucky Resources	[redacted]	$3.05	[redacted]	Gen 2018-02	1

Notes:
The contract $/MMBTU refers to the initial price of the contract at its inception. This price could be subject to escalation per the terms of the contract. All prices are determined on a fully delivered basis. Index values have also been calculated on a delivered basis for comparison purposes.

1. Market indicator price is the average price submitted of all acceptable coal bids.
2. Index based purchase, pricing based on High posting of the Pace Petroleum Coke Index +$2.00.
3. Index based purchase, pricing based on Avg posting of Pace Petroleum Coke Index + $3.00.
4. Price reflects the delivered cost of coal including transportation to, and storage for over a year at, a different terminal on the lower Mississippi at both UBT and Big Bend. [redacted]

- Natural Gas

  Tampa Electric purchases natural gas at prices that are set by published indexes that reflect the market price. Most of the monthly baseload gas is purchased at a price relative to the New York Mercantile Exchange natural gas futures last day settlement price. Tampa Electric purchases additional baseload gas at monthly index prices published in *Inside FERC, Gas Market Report*. Tampa Electric uses the indexes representing market prices for natural gas on the Gulf Coast that can be transported to Tampa Electric's service area: Henry Hub, Mobile Bay, Transco, Zone 4, or Florida Gas Transmission ("FGT") Zone 1, Zone 2 or Zone 3. For daily and short-term natural gas, Tampa Electric typically purchases natural gas based on the FGT index price published in *Gas Daily*. In rare instances, Tampa Electric also purchases small volumes of spot natural gas needed for short durations at fixed prices. Since the price of natural gas Tampa Electric purchases is based upon a published market index, the company's natural gas purchases are at market.

- No. 2 Oil
  Tampa Electric purchases No. 2 oil for combustion turbines at Polk Station. The purchase price is based upon the daily index price published in Platt's *Oilgram* for Gulf Coast Waterborne spot purchases of ultra-low sulfur No. 2 oil. Since the price is determined by the published market index, the price paid by Tampa Electric is at market.

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DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY

OF

JEREMY B. CAIN

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2020 – DECEMBER 2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 66
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: Jeremy B. Cain JC-1

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2020 - DECEMBER 2020
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2020 - DECEMBER 2020

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	21,602.7	10,774.1
+9	19,442.5	9,696.7
+8	17,282.2	8,619.3
+7	15,121.9	7,541.9
+6	12,961.6	6,464.5
+5	10,801.4	5,387.1
+4	8,641.1	4,309.6
+3	6,480.8	3,232.2
+2	4,320.5	2,154.8
+1	2,160.3	1,077.4
0	0.0	0.0
-1	(1,976.7)	(1,077.4)
-2	(3,953.4)	(2,154.8)
-3	(5,930.1)	(3,232.2)
-4	(7,906.8)	(4,309.6)
-5	(9,883.5)	(5,387.1)
-6	(11,860.2)	(6,464.5)
-7	(13,836.9)	(7,541.9)
-8	(15,813.6)	(8,619.3)
-9	(17,790.3)	(9,696.7)
-10	(19,767.0)	(10,774.1)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2020 - DECEMBER 2020

Line 1	Beginning of period balance of common equity: End of month common equity:		$	3,168,529,000
Line 2	Month of January	2020	$	3,093,371,000
Line 3	Month of February	2020	$	3,119,793,544
Line 4	Month of March	2020	$	3,146,441,780
Line 5	Month of April	2020	$	3,195,404,857
Line 6	Month of May	2020	$	3,222,698,940
Line 7	Month of June	2020	$	3,250,226,160
Line 8	Month of July	2020	$	3,174,204,129
Line 9	Month of August	2020	$	3,201,317,123
Line 10	Month of September	2020	$	3,228,661,706
Line 11	Month of October	2020	$	3,277,804,312
Line 12	Month of November	2020	$	3,305,802,224
Line 13	Month of December	2020	$	3,334,039,285
Line 14	(Summation of line 1 through line 13 divided by 13)		$	3,209,099,543
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			74.46%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	10,774,122
Line 18	Jurisdictional Sales			19,521,559 MWH
Line 19	Total Sales			19,521,559 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)		$	10,774,122
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)		$	10,774,122

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 2020 - DECEMBER 2020

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 4	1.40%	55.4	61.0	44.1	301.8	(1,622.9)
POLK 1	3.15%	75.5	79.1	68.3	680.0	(107.9)
POLK 2	6.84%	84.9	86.1	82.7	1,477.8	(823.7)
BAYSIDE 1	5.63%	91.7	92.4	90.3	1,216.3	(475.9)
BAYSIDE 2	8.39%	88.9	90.1	86.4	1,811.8	(621.7)
GPIF SYSTEM	**25.40%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 4	4.43%	10,837	52.3	10,410	11,264	956.4	(956.4)
POLK 1	11.15%	10,018	84.8	8,607	11,429	2,408.6	(2,408.6)
POLK 2	35.96%	7,209	72.9	6,816	7,603	7,768.2	(7,768.2)
BAYSIDE 1	7.64%	7,379	84.2	7,260	7,498	1,649.5	(1,649.5)
BAYSIDE 2	15.43%	7,499	70.9	7,250	7,749	3,332.3	(3,332.3)
GPIF SYSTEM	**74.60%**						

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 20 - DEC 20 POF	TARGET PERIOD JAN 20 - DEC 20 EUOF	TARGET PERIOD JAN 20 - DEC 20 EUOR	ACTUAL PERFORMANCE JAN 18 - DEC 18 POF	ACTUAL PERFORMANCE JAN 18 - DEC 18 EUOF	ACTUAL PERFORMANCE JAN 18 - DEC 18 EUOR	ACTUAL PERFORMANCE JAN 17 - DEC 17 POF	ACTUAL PERFORMANCE JAN 17 - DEC 17 EUOF	ACTUAL PERFORMANCE JAN 17 - DEC 17 EUOR	ACTUAL PERFORMANCE JAN 16 - DEC 16 POF	ACTUAL PERFORMANCE JAN 16 - DEC 16 EUOF	ACTUAL PERFORMANCE JAN 16 - DEC 16 EUOR
BIG BEND 4	1.40%	5.5%	21.8	22.8	29.1	19.1	20.6	26.6	0.0	30.7	31.2	6.7	18.8	21.9
POLK 1	3.15%	12.4%	8.5	16.0	17.5	28.1	10.7	16.3	4.4	9.6	10.4	13.3	4.2	16.4
POLK 2	6.84%	26.9%	12.6	2.5	2.9	2.0	3.3	3.2	1.8	6.9	7.8	0.0	4.5	48.5
BAYSIDE 1	5.63%	22.2%	6.6	1.7	1.9	5.3	1.6	1.7	11.6	2.0	2.4	20.0	1.3	1.8
BAYSIDE 2	8.39%	33.0%	6.6	4.5	4.9	19.6	2.5	3.1	9.4	5.1	5.7	7.1	2.9	5.0
GPIF SYSTEM	**25.40%**	**100.0%**	**9.3**	**5.8**	**6.6**	**12.7**	**4.5**	**5.8**	**6.7**	**6.9**	**7.5**	**8.8**	**4.0**	**18.3**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**84.9**			**82.8**			**86.4**			**87.2**	

3 PERIOD AVERAGE POF	3 PERIOD AVERAGE EUOF	3 PERIOD AVERAGE EUOR	3 PERIOD AVERAGE EAF
9.4	**5.1**	**10.5**	**85.5**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 20 - DEC 20	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 18 - DEC 18	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 17 - DEC 17	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 16 - DEC 16
BIG BEND 4	4.43%	5.9%	10,837	10,921	10,852	10,619
POLK 1	11.15%	14.9%	10,018	10,304	10,140	9,959
POLK 2	35.96%	48.2%	7,209	7,134	7,190	8,306
BAYSIDE 1	7.64%	10.2%	7,379	7,366	7,317	7,442
BAYSIDE 2	15.43%	20.7%	7,499	7,400	7,444	7,574
GPIF SYSTEM	**74.60%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**7,922**	**7,911**	**7,914**	**8,450**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2020 - DECEMBER 2020
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	435,826.93	435,525.16	301.77	1.40%
EA_1 POLK 1	435,826.93	435,146.88	680.05	3.15%
EA_2 POLK 2	435,826.93	434,349.08	1,477.85	6.84%
EA_3 BAYSIDE 1	435,826.93	434,610.61	1,216.32	5.63%
EA_4 BAYSIDE 2	435,826.93	434,015.13	1,811.80	8.39%
AVERAGE HEAT RATE				
AHR_3 BIG BEND 4	435,826.93	434,870.57	956.36	4.43%
AHR_1 POLK 1	435,826.93	433,418.34	2,408.59	11.15%
AHR_2 POLK 2	435,826.93	428,058.70	7,768.23	35.96%
AHR_3 BAYSIDE 1	435,826.93	434,177.45	1,649.48	7.64%
AHR_4 BAYSIDE 2	435,826.93	432,494.64	3,332.29	15.43%
TOTAL SAVINGS			**21,602.74**	**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.

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

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
	Weighting Factor =	1.40%		Weighting Factor =	4.43%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

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

GPIF TARGET AND RANGE SUMMARY

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
	Weighting Factor =	6.84%		Weighting Factor =	35.96%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

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
					7,304
0	0.0	91.7	0	0.0	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
-8	(380.7)	90.6	-8	(1,319.6)	7,489
-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

GPIF TARGET AND RANGE SUMMARY

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

ESTIMATED 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
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. EAF (%)	70.9	4.9	0.0	42.5	70.9	70.9	70.9	70.9	70.9	70.9	68.5	50.3	55.4
2. POF	0.0	93.1	100.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	29.0	21.8
3. EUOF	29.1	2.0	0.0	17.5	29.1	29.1	29.1	29.1	29.1	29.1	28.2	20.7	22.8
4. EUOR	29.1	29.1	0.0	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	624	41	0	120	177	303	588	624	603	162	199	443	3,884
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	120	655	743	600	567	417	156	120	117	582	522	301	4,900
9. POH	0	648	743	288	0	0	0	0	0	0	24	216	1,919
10. EFOH	148	10	0	86	148	143	148	148	143	148	138	105	1,363
11. EMOH	69	4	0	40	69	67	69	69	67	69	65	49	637
12. OPER BTU (GBTU)	1,128	69	0	225	319	640	1,171	1,273	1,288	329	425	806	7,676
13. NET GEN (MWH)	103,820	6,380	0	20,750	29,350	59,180	108,140	117,580	119,150	30,400	39,290	74,240	708,280
14. ANOHR (Btu/kwh)	10,863	10,879	11,112	10,850	10,861	10,816	10,833	10,826	10,812	10,827	10,813	10,862	10,837
15. NOF (%)	47.3	44.2	0.0	49.8	47.8	56.3	53.0	54.3	56.9	54.1	56.9	47.6	52.3
16. NPC (MW)	352	352	352	347	347	347	347	347	347	347	347	352	349
17. ANOHR EQUATION	ANOHR = NOF(	-5.260	) +	11,112									

TAMPA ELECTRIC COMPANY

ESTIMATED 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
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. EAF (%)	77.2	59.7	82.5	82.5	82.5	82.5	82.5	82.5	35.8	71.9	82.5	82.5	75.5
2. POF	6.5	27.6	0.0	0.0	0.0	0.0	0.0	0.0	56.7	12.9	0.0	0.0	8.5
3. EUOF	16.4	12.7	17.5	17.5	17.5	17.5	17.5	17.5	7.6	15.2	17.5	17.5	16.0
4. EUOR	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	74	75	128	293	294	367	360	402	148	350	387	179	3,057
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	670	621	615	427	450	353	384	342	572	394	334	565	5,727
9. POH	48	192	0	0	0	0	0	0	408	96	0	0	744
10. EFOH	64	47	69	67	69	67	69	69	29	60	67	69	745
11. EMOH	57	41	61	59	61	59	61	61	26	53	59	61	662
12. OPER BTU (GBTU)	130	133	236	528	533	678	668	742	272	649	706	345	5,629
13. NET GEN (MWH)	12,870	13,120	23,380	52,810	53,240	67,900	67,000	74,360	27,190	65,010	70,640	34,360	561,880
14. ANOHR (Btu/kwh)	10,122	10,117	10,079	10,007	10,002	9,981	9,975	9,981	9,988	9,977	9,994	10,033	10,018
15. NOF (%)	75.6	76.1	79.4	85.8	86.2	88.1	88.6	88.1	87.5	88.4	86.9	83.5	84.8
16. NPC (MW)	230	230	230	210	210	210	210	210	210	210	210	230	217
17. ANOHR EQUATION	ANOHR = NOF(	-11.267	) +	10,974									

TAMPA ELECTRIC COMPANY

ESTIMATED 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
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. EAF (%)	97.1	97.1	68.9	80.9	68.9	97.1	97.1	97.1	68.0	81.5	68.0	97.1	84.9
2. POF	0.0	0.0	29.1	16.7	29.0	0.0	0.0	0.0	30.0	16.1	30.0	0.0	12.6
3. EUOF	2.9	2.9	2.0	2.4	2.0	2.9	2.9	2.9	2.0	2.4	2.0	2.9	2.5
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	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	723	680	735	583	725	711	735	735	706	611	700	735	8,379
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	21	16	8	137	19	9	9	9	14	133	21	9	405
9. POH	0	0	216	120	216	0	0	0	216	120	216	0	1,104
10. EFOH	11	10	8	9	8	10	11	11	7	9	7	11	110
11. EMOH	11	10	8	9	8	10	11	11	7	9	7	11	110
12. OPER BTU (GBTU)	4,757	4,469	4,916	3,077	3,964	4,123	4,250	4,246	3,791	3,272	3,678	4,001	48,758
13. NET GEN (MWH)	687,400	644,830	723,940	409,440	541,220	593,630	610,220	608,910	510,640	439,810	488,080	505,080	6,763,200
14. ANOHR (Btu/kwh)	6,921	6,930	6,791	7,515	7,325	6,945	6,965	6,973	7,424	7,439	7,536	7,921	7,209
15. NOF (%)	79.2	79.0	82.1	66.2	70.4	78.7	78.2	78.1	68.2	67.8	65.7	57.3	72.9
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(	-45.556	) +	10,530									

TAMPA ELECTRIC COMPANY

ESTIMATED 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. EAF (%)	98.1	94.7	63.3	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	60.1	91.7
2. POF	0.0	3.4	35.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.7	6.6
3. EUOF	1.9	1.8	1.2	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.1	1.7
4. EUOR	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	730	659	466	706	730	706	730	730	706	730	707	432	8,032
7. RSH	0	0	4	1	0	1	0	0	1	0	1	15	22
8. UH	14	37	273	13	14	13	14	14	13	14	13	297	730
9. POH	0	24	264	0	0	0	0	0	0	0	0	288	576
10. EFOH	4	3	2	4	4	4	4	4	4	4	4	2	42
11. EMOH	10	9	7	10	10	10	10	10	10	10	10	6	111
12. OPER BTU (GBTU)	3,243	2,701	2,033	3,132	3,304	3,299	3,417	3,466	3,318	3,351	3,168	2,045	36,494
13. NET GEN (MWH)	437,950	363,850	274,470	424,760	448,430	448,310	464,330	471,280	450,860	454,950	429,760	276,810	4,945,760
14. ANOHR (Btu/kwh)	7,404	7,422	7,408	7,374	7,369	7,360	7,359	7,355	7,358	7,365	7,371	7,389	7,379
15. NOF (%)	75.7	69.7	74.4	85.8	87.6	90.6	90.7	92.1	91.1	88.9	86.7	80.9	84.2
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(		-2.997	) +		7,631							

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2020 - DECEMBER 2020

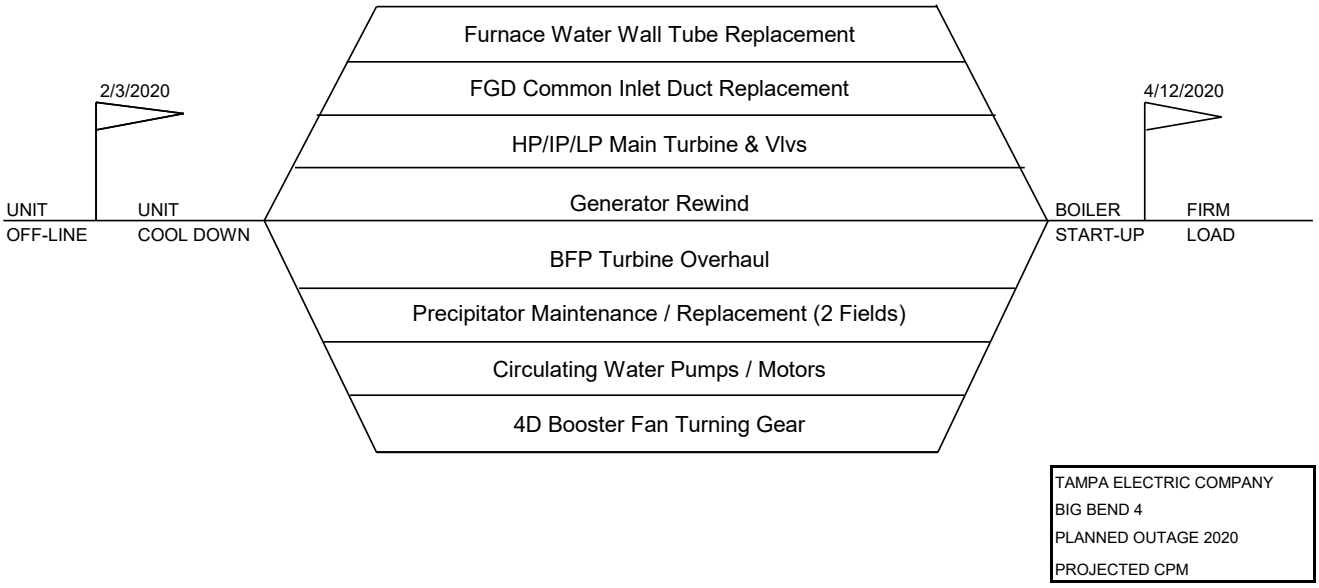
PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020
1. EAF (%)	95.1	55.8	95.1	95.1	95.1	95.1	95.1	95.1	95.1	95.1	57.1	95.1	88.9
2. POF	0.0	41.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.9	0.0	6.6
3. EUOF	4.9	2.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	2.9	4.9	4.5
4. EUOR	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
5. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
6. SH	392	130	471	674	707	684	707	707	684	698	366	707	6,927
7. RSH	316	258	236	11	1	1	1	1	1	10	46	1	882
8. UH	36	308	36	35	36	35	36	36	35	36	309	36	975
9. POH	0	288	0	0	0	0	0	0	0	0	288	0	576
10. EFOH	16	9	16	16	16	16	16	16	16	16	9	16	179
11. EMOH	20	11	20	19	20	19	20	20	19	20	12	20	220
12. OPER BTU (GBTU)	1,324	459	1,879	3,217	3,592	3,816	3,980	4,131	3,900	3,708	1,708	3,832	35,640
13. NET GEN (MWH)	172,180	59,800	245,980	428,000	479,980	513,330	535,850	557,770	525,600	497,050	226,890	510,090	4,752,520
14. ANOHR (Btu/kwh)	7,692	7,679	7,639	7,516	7,484	7,433	7,428	7,405	7,420	7,461	7,527	7,512	7,499
15. NOF (%)	42.0	43.9	49.9	68.4	73.1	80.8	81.6	84.9	82.7	76.7	66.7	68.9	70.9
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(		-6.669	) +		7,972							

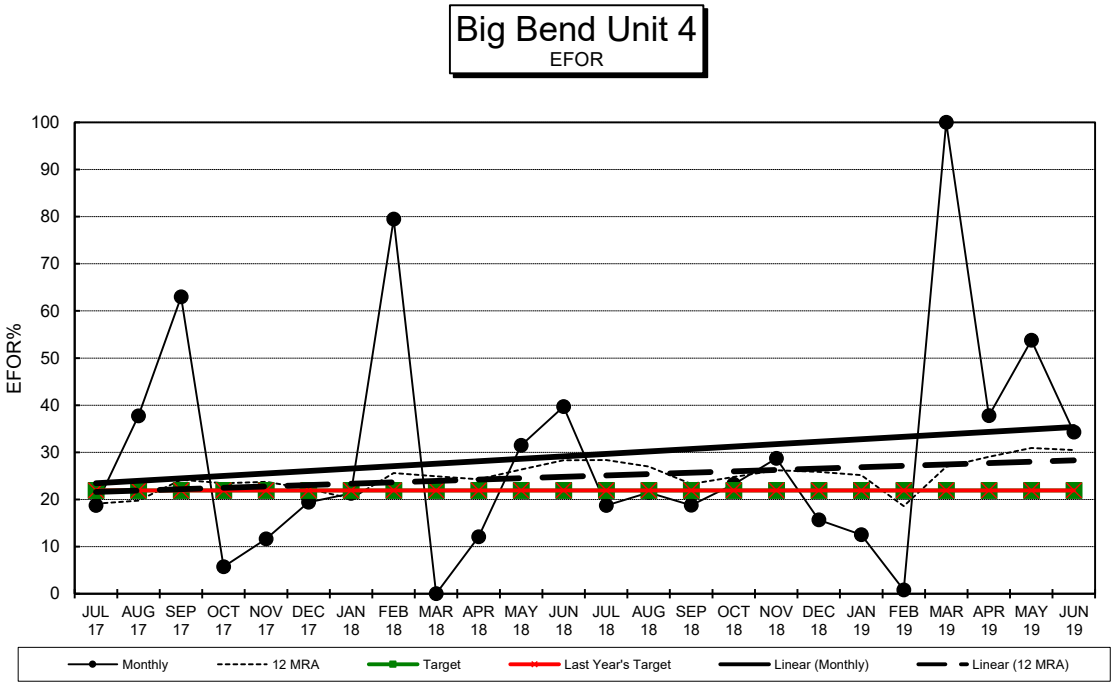
TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2020 - DECEMBER 2020

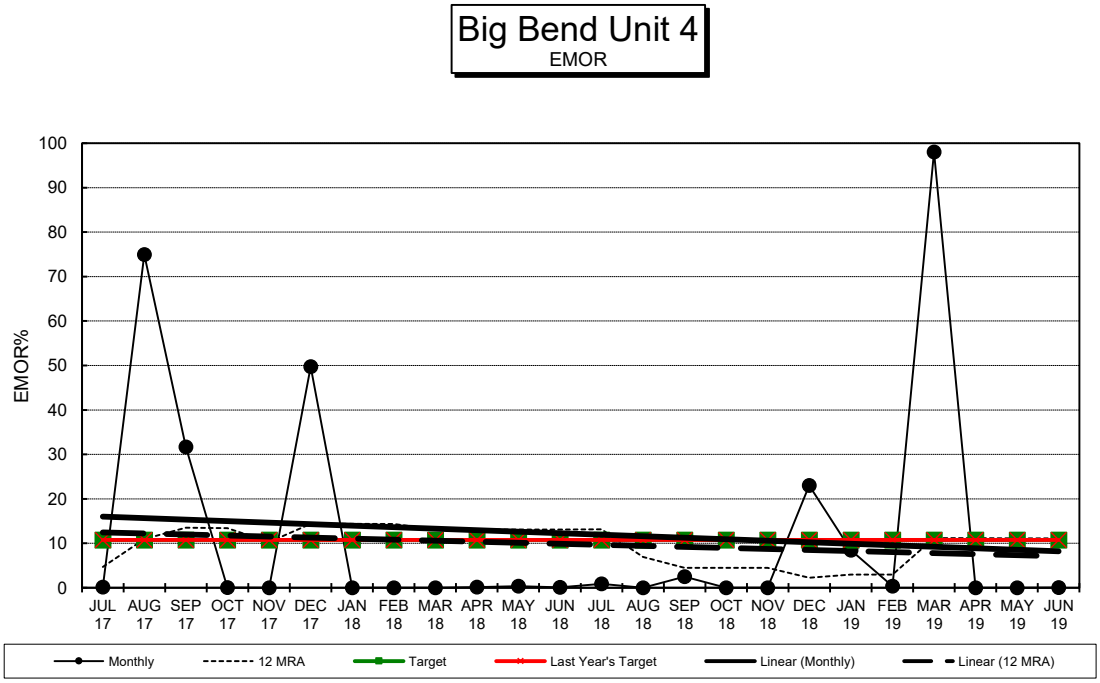
PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
+ BIG BEND 4	Feb 03 - Apr 12	Furnace Water Wall Tube Replacement, FGD Common Inlet Duct Replacement, Precipitator Maintenance, BFP Turbine Overhaul, 4D Booster Fan Turning Gear, Circulating Water Pumps / Motors, HP/IP/LP Main Turbine & Vlvs, Generator Rewind
	Nov 30 - Dec 09	Fuel System Clean-up Planned Outage
POLK 1	Jan 30 - Feb 08	Combined Cycle & Gasifier Planned Outage
	Sep 14 - Oct 04	Combined Cycle & Gasifier Planned Outage
POLK 2	Apr 13 - Apr 17	Combined Cycle Planned Outage
	Oct 23 - Oct 27	Combined Cycle Planned Outage
BAYSIDE 1	Feb 29 - Mar 11	Combined Cycle Planned Outage
	Dec 02 - Dec 13	Combined Cycle Planned Outage
BAYSIDE 2	Feb 13 - Feb 24	Combined Cycle Planned Outage
	Nov 12 - Nov 23	Combined Cycle Planned Outage

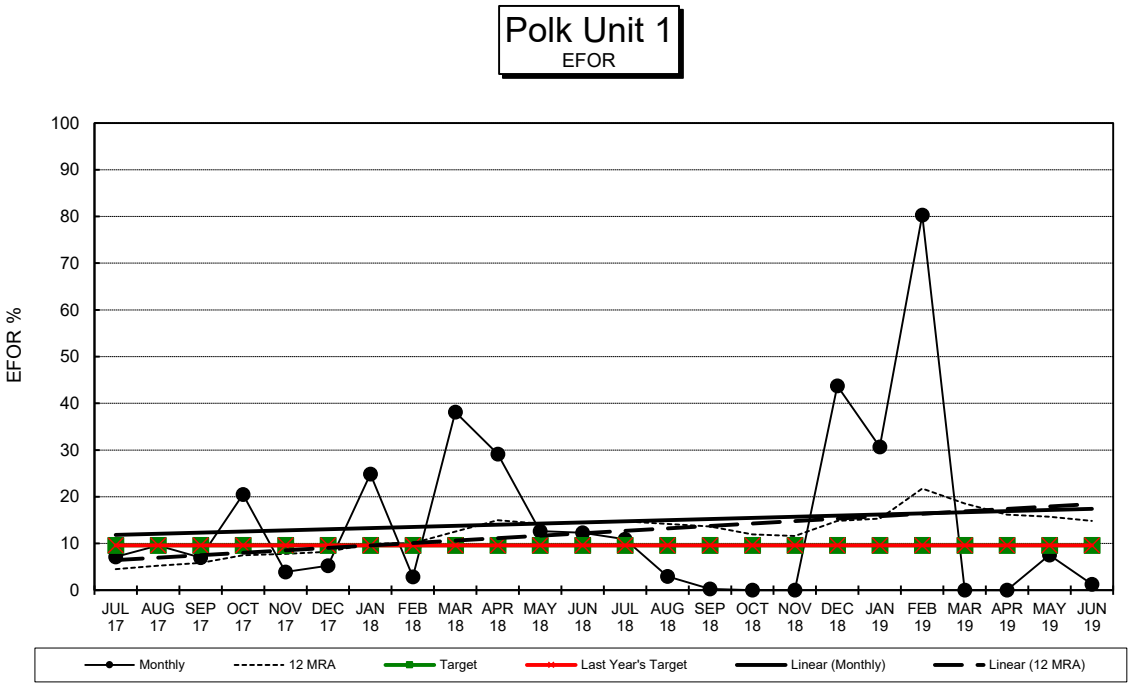
+ These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.

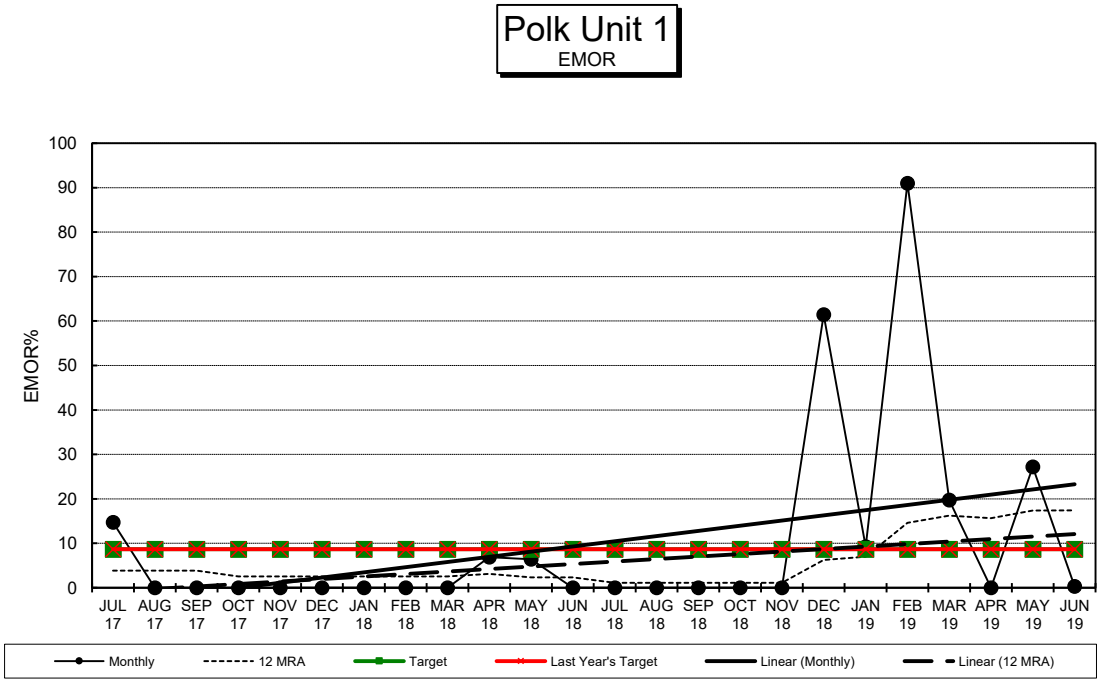
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2020 - DECEMBER 2020

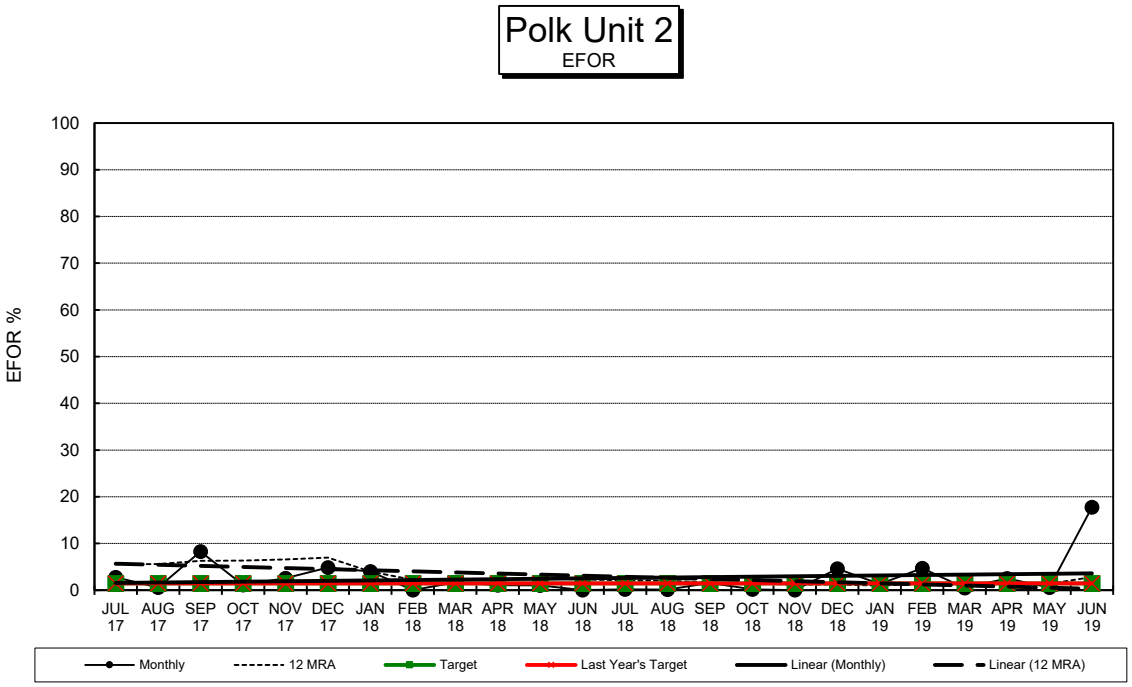


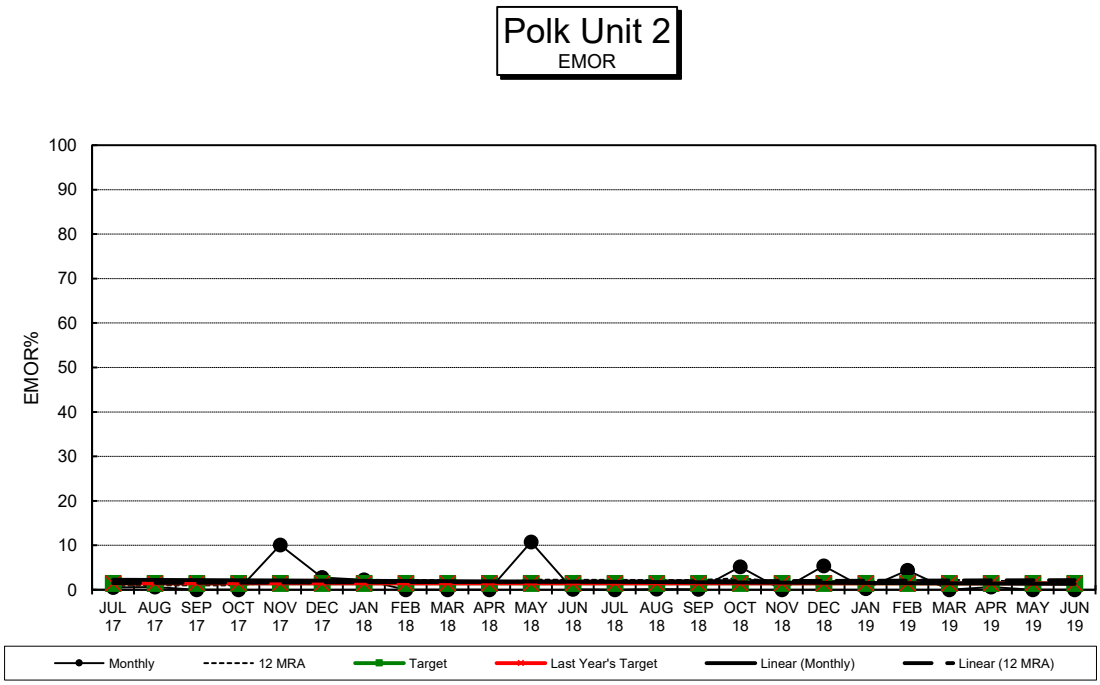

Big Bend Unit 4
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

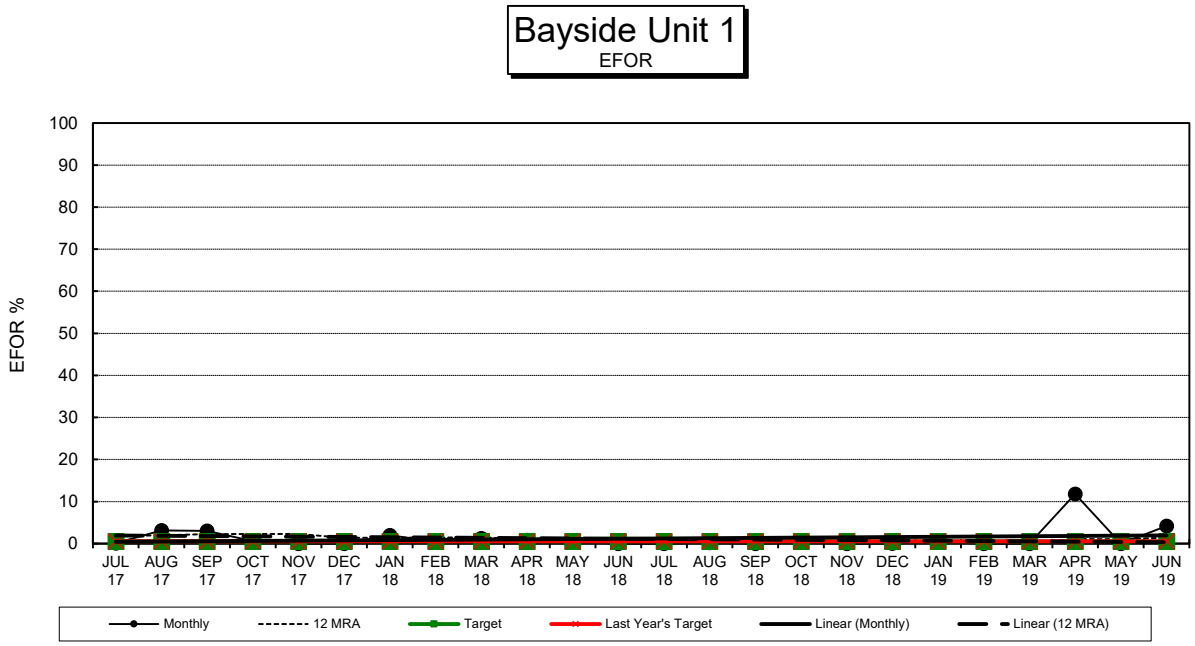

Big Bend Unit 4
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

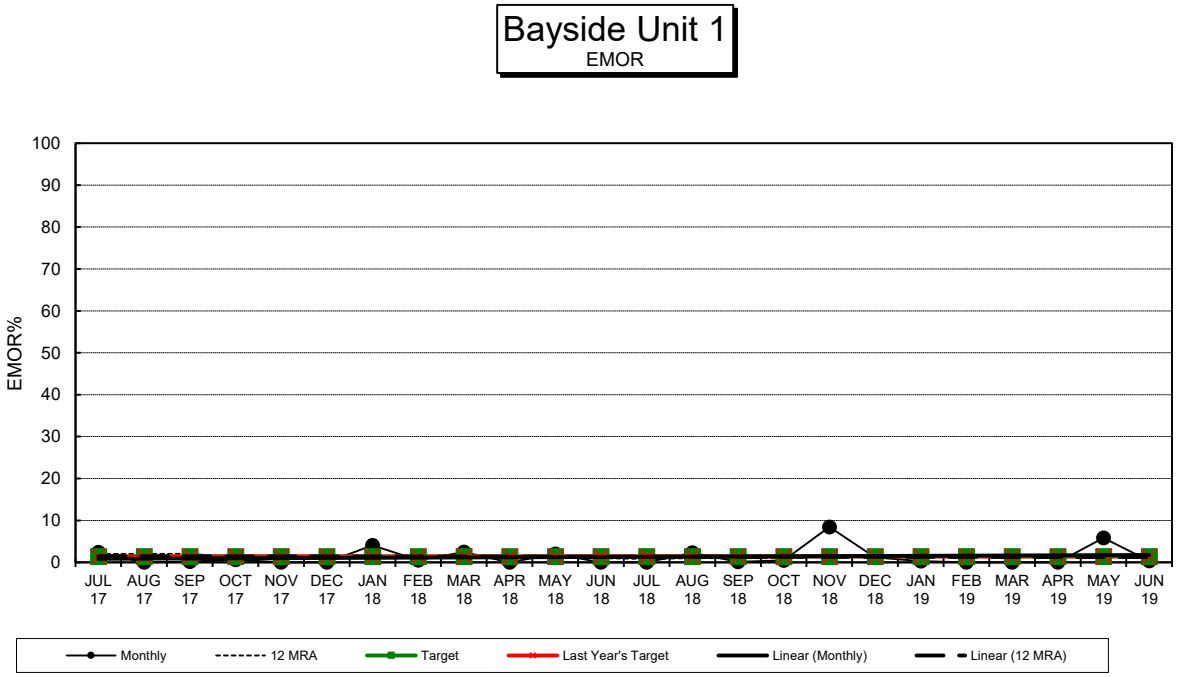

Polk Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

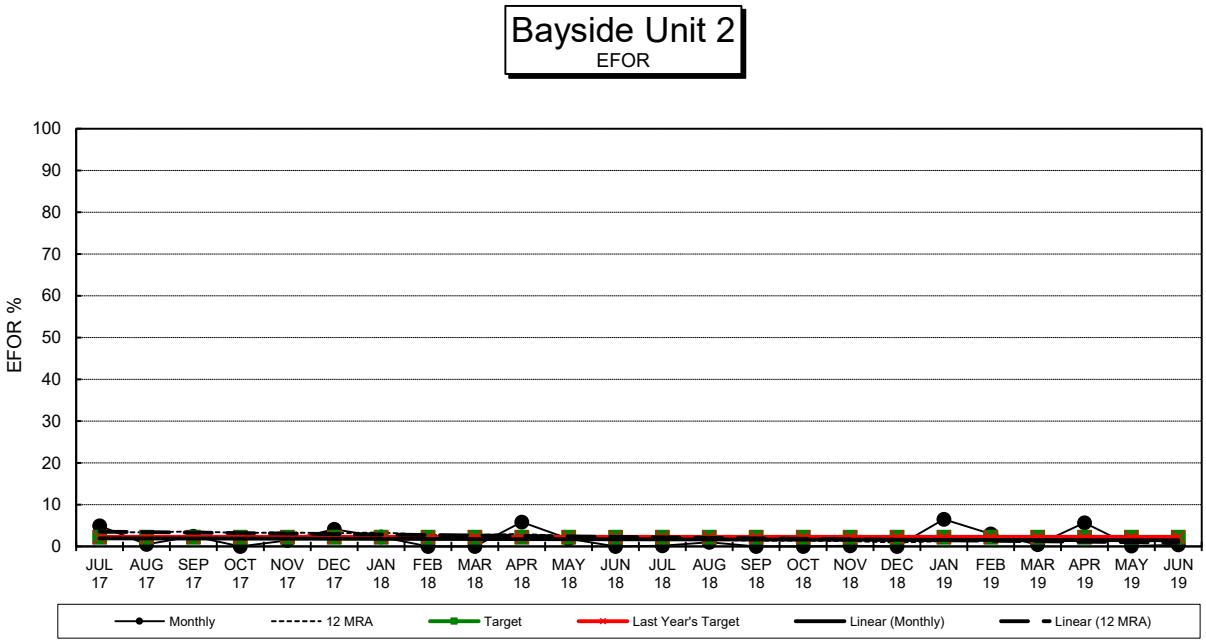

Polk Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

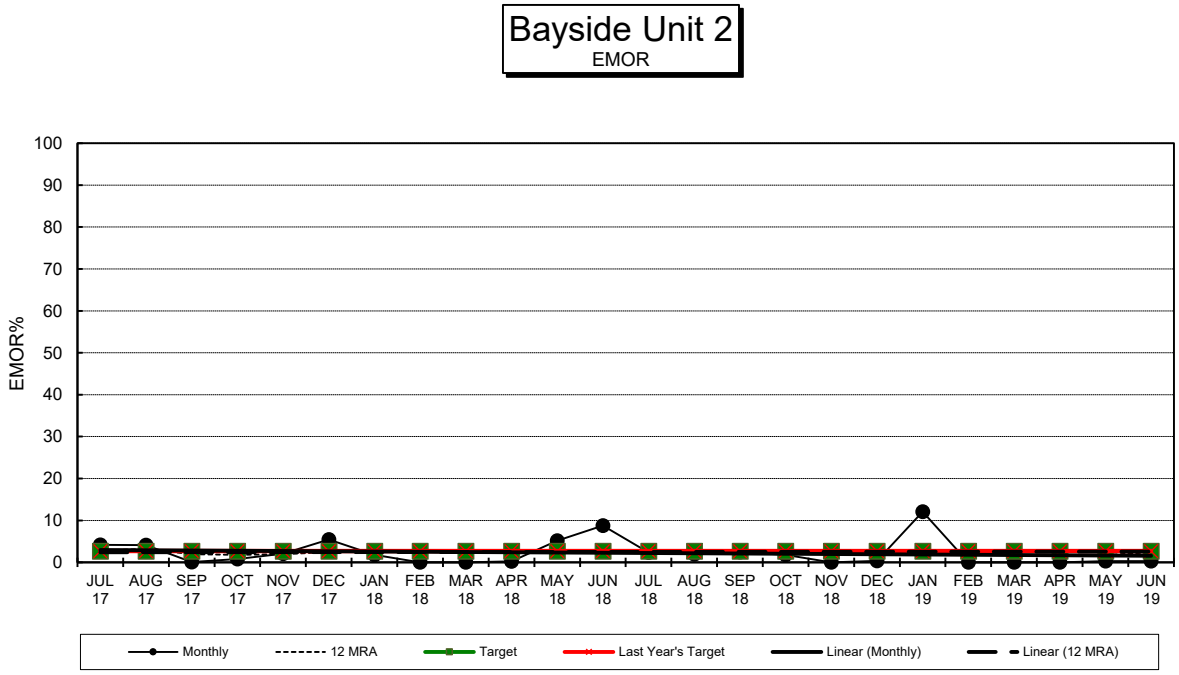

Polk Unit 2
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

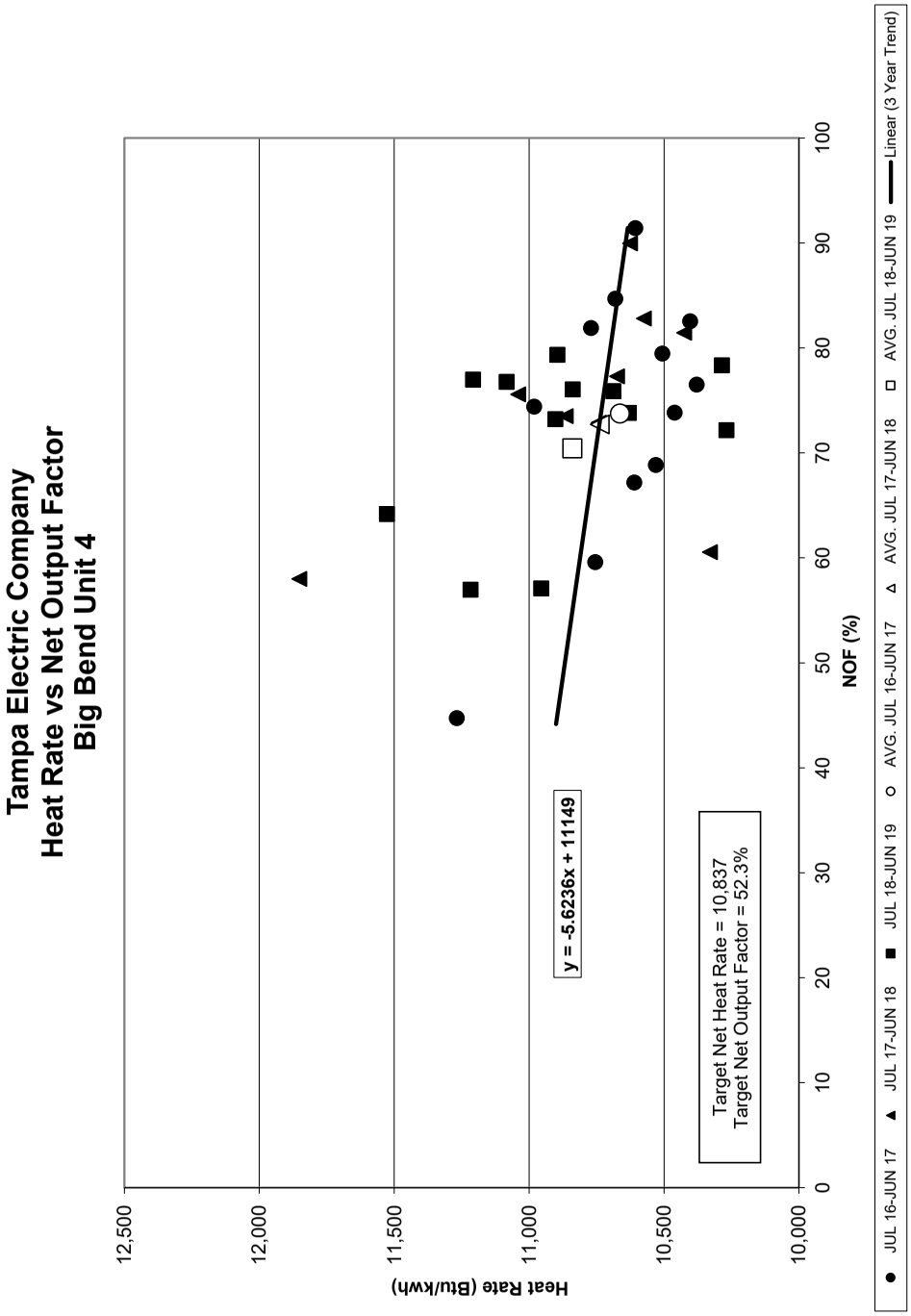

Polk Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

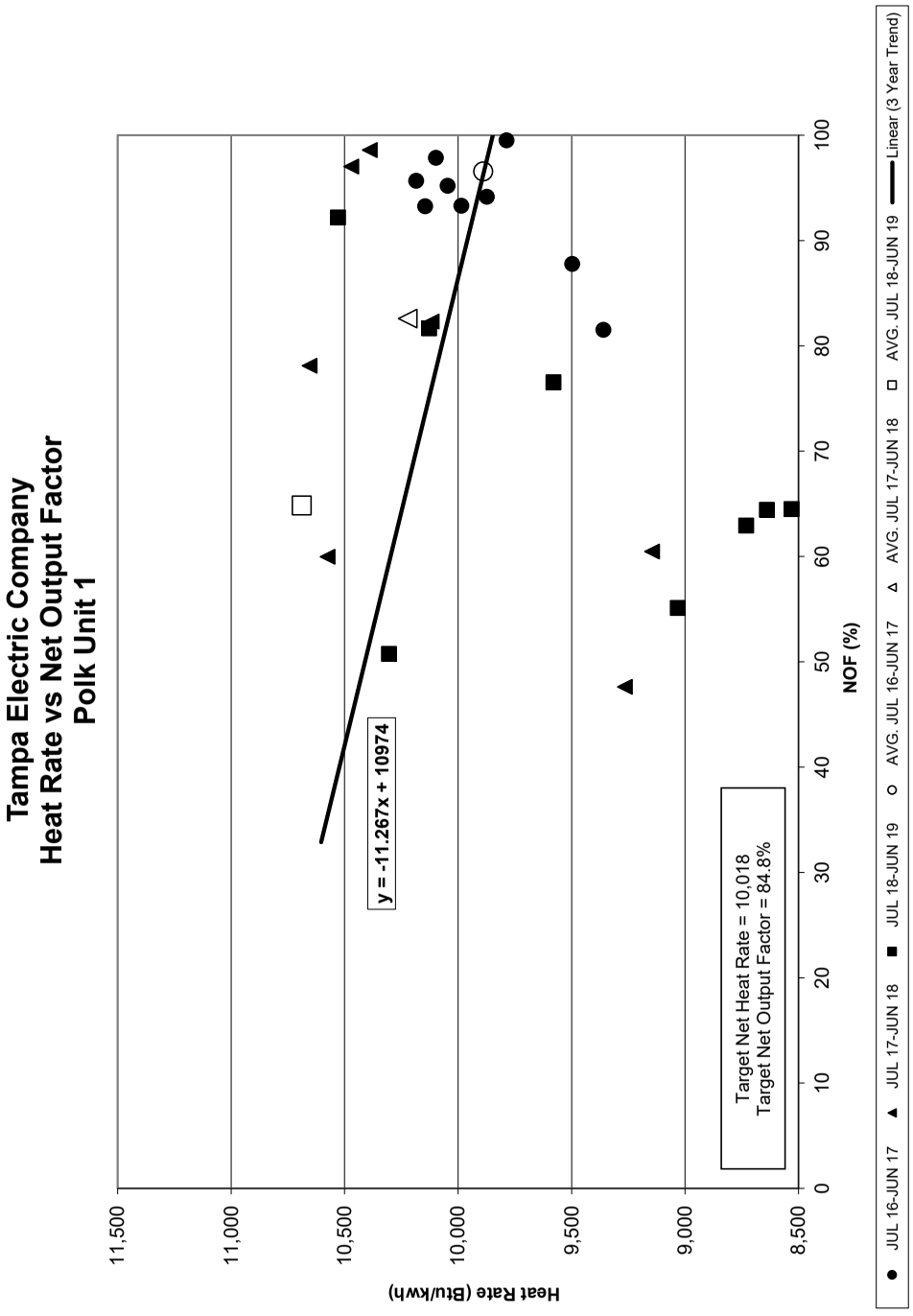

Bayside Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

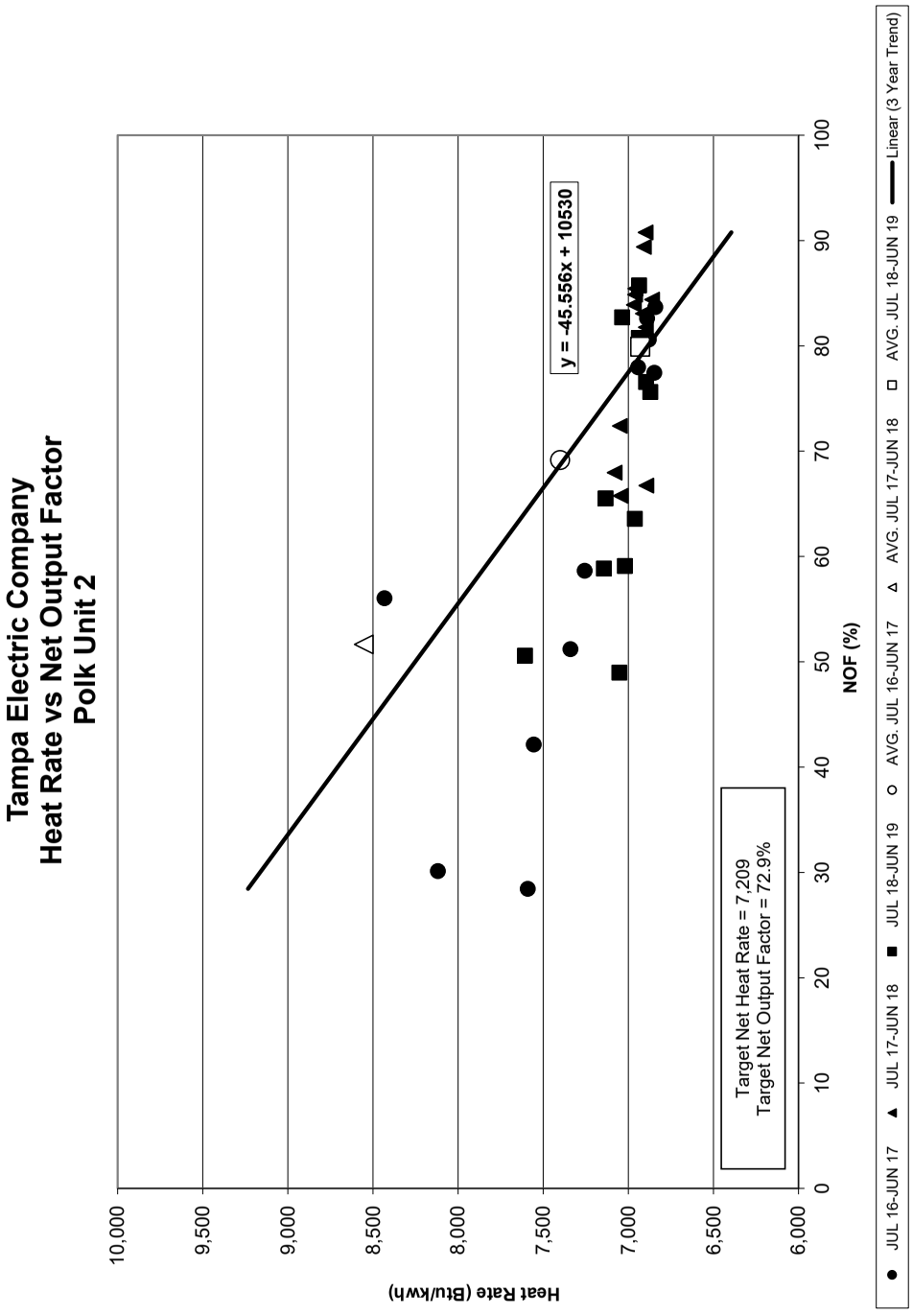

Bayside Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

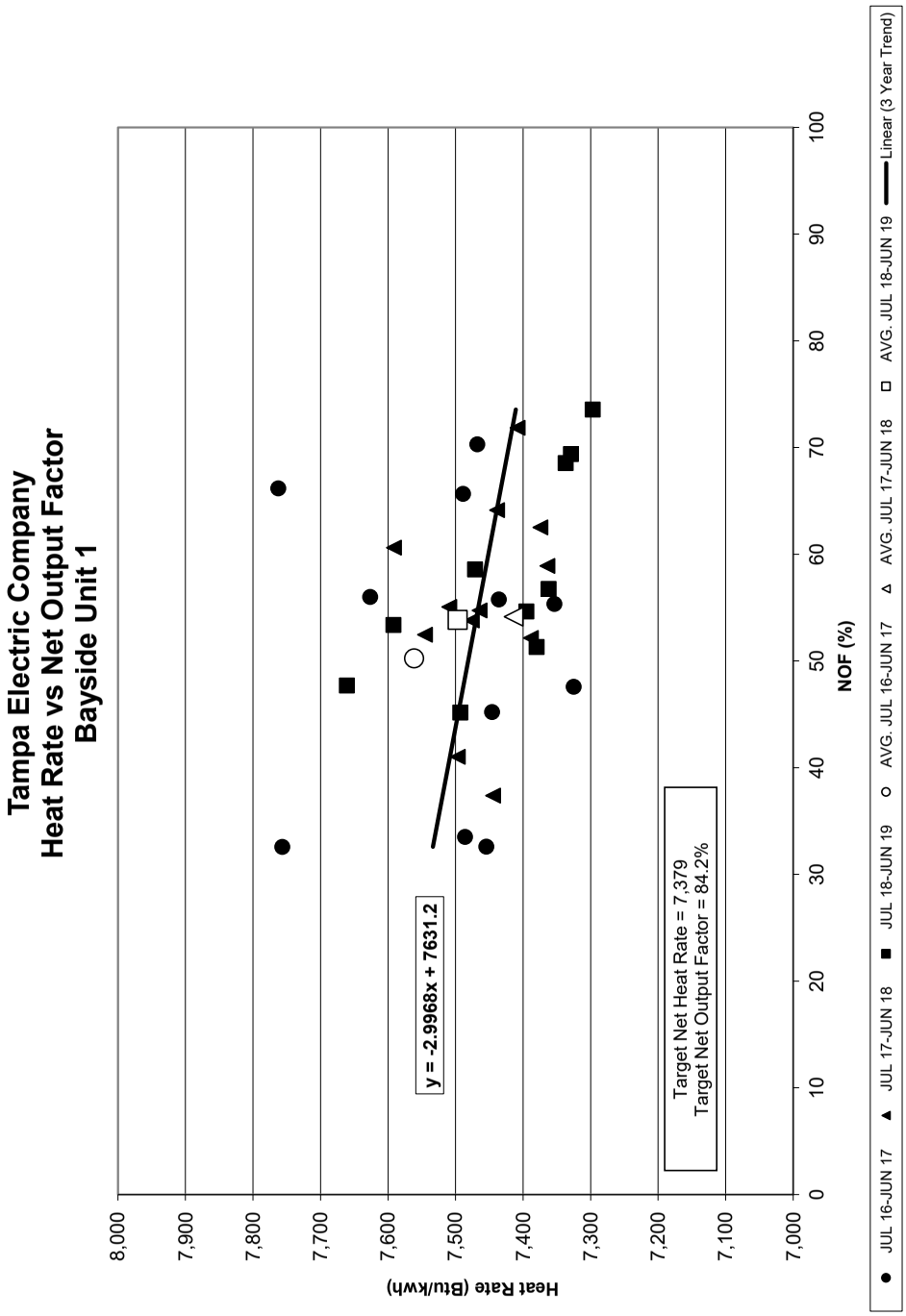

Bayside Unit 2
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

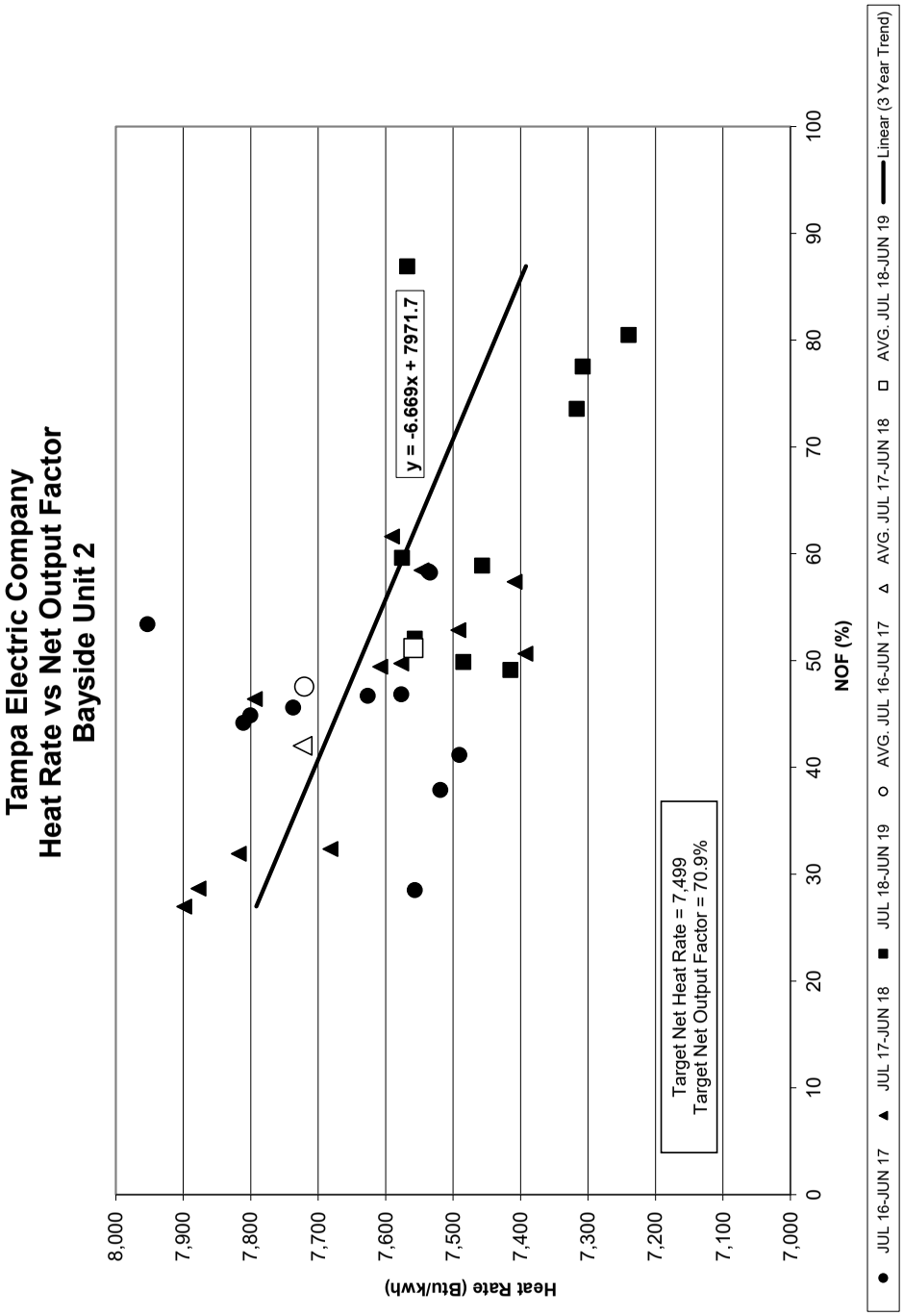

Bayside Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 17
AUG 17
SEP 17
OCT 17
NOV 17
DEC 17
JAN 18
FEB 18
MAR 18
APR 18
MAY 18
JUN 18
JUL 18
AUG 18
SEP 18
OCT 18
NOV 18
DEC 18
JAN 19
FEB 19
MAR 19
APR 19
MAY 19
JUN 19
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4
Heat Rate (Btu/kwh)
12,500
12,000
11,500
11,000
10,500
10,000
NOF (%)
0
10
20
30
40
50
60
70
80
90
100
y = -5.6236x + 11149
Target Net Heat Rate = 10,837
Target Net Output Factor = 52.3%
JUL 16-JUN 17
JUL 17-JUN 18
JUL 18-JUN 19
AVG. JUL 16-JUN 17
AVG. JUL 17-JUN 18
AVG. JUL 18-JUN 19
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1
y = -11.267x + 10974
Target Net Heat Rate = 10,018
Target Net Output Factor = 84.8%
Heat Rate (Btu/kwh)
NOF (%)
11,500
11,000
10,500
10,000
9,500
9,000
8,500
0
10
20
30
40
50
60
70
80
90
100
JUL 16-JUN 17
JUL 17-JUN 18
JUL 18-JUN 19
AVG. JUL 16-JUN 17
AVG. JUL 17-JUN 18
AVG. JUL 18-JUN 19
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 2
y = -45.556x + 10530
Target Net Heat Rate = 7,209
Target Net Output Factor = 72.9%
Heat Rate (Btu/kwh)
NOF (%)
10,000
9,500
9,000
8,500
8,000
7,500
7,000
6,500
6,000
0
10
20
30
40
50
60
70
80
90
100
JUL 16-JUN 17
JUL 17-JUN 18
JUL 18-JUN 19
AVG. JUL 16-JUN 17
AVG. JUL 17-JUN 18
AVG. JUL 18-JUN 19
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1
y = -2.9968x + 7631.2
Target Net Heat Rate = 7,379
Target Net Output Factor = 84.2%
Heat Rate (Btu/kwh)
NOF (%)
8,000
7,900
7,800
7,700
7,600
7,500
7,400
7,300
7,200
7,100
7,000
0
10
20
30
40
50
60
70
80
90
100
JUL 16-JUN 17
JUL 17-JUN 18
JUL 18-JUN 19
AVG. JUL 16-JUN 17
AVG. JUL 17-JUN 18
AVG. JUL 18-JUN 19
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2
y = -6.669x + 7971.7
Target Net Heat Rate = 7,499
Target Net Output Factor = 70.9%
Heat Rate (Btu/kwh)
NOF (%)
8,000
7,900
7,800
7,700
7,600
7,500
7,400
7,300
7,200
7,100
7,000
0
10
20
30
40
50
60
70
80
90
100
JUL 16-JUN 17
JUL 17-JUN 18
JUL 18-JUN 19
AVG. JUL 16-JUN 17
AVG. JUL 17-JUN 18
AVG. JUL 18-JUN 19
Linear (3 Year Trend)

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2020 - DECEMBER 2020

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 4		382	349
POLK 1		225	217
POLK 2		1,130	1,107
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,456	3,372
	SYSTEM TOTAL	**5,249**	**5,105**
	% OF SYSTEM TOTAL	**65.8%**	**66.1%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2020 - DECEMBER 2020

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
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	1,954	1,930
BIG BEND 1		323	308
BIG BEND 2		363	343
BIG BEND 3		368	348
BIG BEND 4		382	349
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,495	1,406
POLK 1		225	217
POLK 2		1,130	1,107
	POLK TOTAL	1,355	1,324
SOLAR		445	445
	SOLAR TOTAL	445	445
	SYSTEM TOTAL	**5,249**	**5,105**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2020 - DECEMBER 2020

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	6,763,200	33.31%	33.31%
BAYSIDE	1	4,945,760	24.36%	57.66%
BAYSIDE	2	4,752,520	23.40%	81.07%
SOLAR		1,413,420	6.96%	88.03%
BIG BEND	4	708,280	3.49%	91.51%
POLK	1	561,880	2.77%	94.28%
BIG BEND	3	531,060	2.62%	96.90%
BIG BEND	2	310,710	1.53%	98.43%
BIG BEND	1	183,340	0.90%	99.33%
BAYSIDE	5	40,470	0.20%	99.53%
BAYSIDE	6	34,740	0.17%	99.70%
BAYSIDE	3	28,310	0.14%	99.84%
BAYSIDE	4	19,010	0.09%	99.93%
BIG BEND CT	4	13,510	0.07%	100.00%
TOTAL GENERATION		20,306,210	100.00%	

GENERATION BY COAL UNITS: 708,280 MWH
% GENERATION BY COAL UNITS 3.49%
GENERATION BY NATURAL GAS UNITS: 18,184,510 MWH
% GENERATION BY NATURAL GAS UNITS: 89.55%

GENERATION BY SOLAR UNITS: 1,413,420 MWH
% GENERATION BY SOLAR UNIT 6.96%
GENERATION BY GPIF UNITS: 17,731,640 MWH
% GENERATION BY GPIF UNITS: 87.32%

EXHIBIT TO THE TESTIMONY

OF

JEREMY B. CAIN

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS
JANUARY 2020 – DECEMBER 2020

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2020 - DECEMBER 2020

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 4[1]	55.4	21.8	22.8	10,837
Polk 1[2]	75.5	8.5	16.0	10,018
Polk 2[3]	84.9	12.6	2.5	7,209
Bayside 1[4]	91.7	6.6	1.7	7,379
Bayside 2[5]	88.9	6.6	4.5	7,499

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 2018 – DECEMBER 2018

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 67
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: John C. Heisey JCH-1

TAMPA ELECTRIC
OPTIMIZATION MECHANISM
Actual for the Period: January 2018 through December 2018

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	957,186	9,131	788,141	1,754,458	1,754,458	-	-
February	1,615	190,770	-	192,385	192,385	-	-
March	139,559	264,767	-	404,326	404,326	-	-
April	242,660	11,971	(8,813)	245,818	245,818	-	-
May	299,845	352,904	-	652,749	652,749	-	-
June	306,237	297,177	-	603,414	603,414	-	-
July	152,867	-46,631	685	106,921	106,921	-	-
August	141,559	-46,631	1,621	96,549	96,549	-	-
September	127,807	233,847	(51,872)	309,782	309,782	-	-
October	81,452	550,512	12,715	644,679	133,599	511,080	-
November	18,654	1,155,110	80,159	1,253,922	-	1,253,922	-
December	77,117	234	24,903	102,254	-	102,254	-
Total	**2,546,558**	**2,973,160**	**847,539**	**6,367,256**	**4,500,000**	**1,867,256**	**-**

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	1,754,458	-	-	-	-	1,754,458	-
February	192,385	-	-	-	-	192,385	-
March	404,326	-	-	-	-	404,326	-
April	245,818	-	-	-	-	245,818	-
May	652,749	-	-	-	-	652,749	-
June	603,414	-	-	-	-	603,414	-
July	106,921	-	-	-	-	106,921	-
August	96,549	-	-	-	-	96,549	-
September	309,782	-	-	-	-	309,782	-
October	133,599	204,432	306,647	-	-	338,030	306,647
November	-	501,569	752,353	-	-	501,569	752,353
December	-	40,902	61,352	-	-	40,902	61,352
Total	**4,500,000**	**746,902**	**1,120,353**	**-**	**-**	**5,246,902**	**1,120,353**

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

Wholesale Sales-Table 3

(1)	(2)	(3)	(4)	(5)
Month	Wholesale Sales (MWh)	Wholesale Gross Gains ($)	Third Party Transmission Costs ($)	Total Net Wholesale Sales Gains ($)
				(3) + (4)
January	54,103	1,136,530	(179,344)	957,186
February	765	1,615	-	1,615
March	30,976	140,083	(524)	139,559
April	51,571	242,660	-	242,660
May	32,138	305,838	(5,993)	299,845
June	24,093	311,831	(5,594)	306,237
July	15,478	157,256	(4,389)	152,867
August	16,495	151,126	(9,567)	141,559
September	14,094	134,893	(7,086)	127,807
October	7,222	82,188	(736)	81,452
November	2,604	37,006	(18,352)	18,654
December	8,202	83,030	(5,913)	77,117
Total	**257,741**	**2,784,056**	**(237,498)**	**2,546,558**

Wholesale Purchases-Table 4

(1)	(2)	(3)	(4)	(5)
Month	Wholesale Purchases (MWh)	Wholesale Savings ($)	Capacity Purchases ($)	Total Net Wholesale Purchase Gains ($)
				(3) + (4)
January	2,101	9,131	-	9,131
February	37,394	190,770	-	190,770
March	103,400	264,767	-	264,767
April	4,375	11,971	-	11,971
May	84,140	352,904	-	352,904
June	114,400	297,177	-	297,177
July	117,800	(46,631)	-	(46,631)
August	117,800	(46,631)	-	(46,631)
September	112,400	233,847	-	233,847
October	118,446	550,512	-	550,512
November	9,560	1,155,110	-	1,155,110
December	100	234	-	234
Total	**821,916**	**2,973,160**	**-**	**2,973,160**

TAMPA ELECTRIC
ASSET OPTIMIZATION DETAIL-Table 5
Actual for the Period: January 2018 through December 2018

(1) Month	(2) Natural Gas Delivered City-Gate Sales ($)	(3) Natural Gas Storage Optimization ($)	(4) Natural Gas AMA Gains ($)	(5) Resale of Solid Fuel ($)	(6) Total Asset Optimization Gains ($)
January	[redacted]	[redacted]	[redacted]	[redacted]	788,141
February	[redacted]	[redacted]	[redacted]	[redacted]	-
March	[redacted]	[redacted]	[redacted]	[redacted]	-
April	[redacted]	[redacted]	[redacted]	[redacted]	(8,813)
May	[redacted]	[redacted]	[redacted]	[redacted]	-
June	[redacted]	[redacted]	[redacted]	[redacted]	-
July	[redacted]	[redacted]	[redacted]	[redacted]	685
August	[redacted]	[redacted]	[redacted]	[redacted]	1,621
September	[redacted]	[redacted]	[redacted]	[redacted]	(51,872)
October	[redacted]	[redacted]	[redacted]	[redacted]	12,715
November	[redacted]	[redacted]	[redacted]	[redacted]	80,159
December	[redacted]	[redacted]	[redacted]	[redacted]	24,903
Total	**2,131**	**754,225**	**90,209**	**974**	**847,539**

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 68
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-1

GDS Associates, Inc
ENGINEERS & CONSULTANTS

Richard A. Polich, P.E.
Managing Director – Power Supply Services

EDUCATION

Master of Business Administration, University of Michigan, 1990
Bachelor of Science, Mechanical Engineering, University of Michigan, 1979
Bachelor of Science, Nuclear Engineering, University of Michigan, 1979

ENGINEERING REGISTRATION

Professional Engineer in the State of Michigan

PROFESSIONAL MEMBERSHIP

National Society of Professional Engineers
American Nuclear Society
American Society of Mechanical Engineers

PROFESSIONAL EXPERIENCE

Mr. Polich has more than 30 years' experience as an energy industry engineer, manager, and leader, combining his business and technical expertise in the management of governmental, industrial and utility projects. He has worked extensively in nuclear, coal, IGCC, natural gas, green/renewable generation. Mr. Polich has developed generation projects in wind, solar, and biomass in Australia, Canada, Caribbean, South American and United States. His generation experience includes engineering of systems and providing engineering support of plant operations. Notable projects include the Midland Nuclear Project and its conversion to natural gas combined cycle, start-up testing support for Consumers' coal-fired Campbell 3, Palisades nuclear steam generator replacement support, Covert Generating Station feasibility evaluation, and a Lake Erie offshore wind project. He also has extensive experience in utility rates and regulation, having managed Consumers Energy's rates group for a number of years. In that function his responsibilities included load and revenue forecasting, overseeing the design of gas and electric rates and testifying in regulatory proceedings. Mr. Polich has testified in over thirty regulatory and legislative proceedings.

Mr. Polich has been involved in the nuclear industry since 1978. While at GDS, Mr. Polich has provided Utah Associated Municipal Power System project cost analysis for a small modular nuclear power project. Last year, he provided advisory services to the Vermont Public Utility Commission on the ownership transfer, nuclear decommissioning trust fund adequacy and decommissioning methodology of Vermont Yankee. Mr. Polich has supported GDS oversight efforts of the construction of the Vogel Nuclear Plant units 2&3 for the Georgia Public Service Commission. He has also provided decommissioning assessment analysis on St. Lucie Nuclear, and Grand Gulf Nuclear projects. Mr. Polich was part of the design engineering team for the Erie Nuclear Plant by the design engineering firm, Gilbert Commonwealth. Key responsibilities were the design of systems and component specifications associated with the nuclear steam supply systems (NSSS) and steam turbine thermal cycle. Worked directly with Babcock and Wilcox on NSSS design and ancillary system specifications. Mr. Polich was also senior engineer on the Midland Nuclear project, responsible for oversight of Bechtel design engineering and interfacing with NSSS vendor Babcock & Wilcox on ancillary systems. His responsibilities also included negotiation with the Nuclear Regulatory Commission on new regulation requirements. Mr. Polich's role evolved into onsite engineering during construction of the Midland Nuclear Plant and as a project trouble shooter at the Palisades Nuclear Plant.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 68
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E.

GDS Associates, Inc
ENGINEERS & CONSULTANTS

Richard A. Polich, P.E.
Managing Director – Power Supply Services

SPECIFIC PROJECT EXPERIENCE

NUCLEAR PROJECT EXPERIENCE

Vermont Yankee – Provided the Vermont Public Utility Commission advisory services on the asset transfer of Vermont Yankee from Entergy Nuclear Operations, Inc. to NorthStar Group Holdings, LLC. This effort has included assessment of financial strength of new company, adequacy of Nuclear Decommissioning Trust Fund to fund decommissioning efforts, evaluation of decommissioning methodology and State of Vermont Risk.

Vogel Nuclear Plant Units 3 & 4 – Mr. Polich has provided advisory services to the team performing the oversight of the construction of the Vogel Plant Units 3 & 4 as part of GDS project oversight responsibilities for the Georgia Public Service Commission.

St. Lucie Nuclear Plant – Provided a risk assessment, decommissioning funding study and ownership evaluation for City of Vero Beach. This included review of project maintenance history, steam generator replacement project, analysis of decommissioning needs and funding and assessing current value of Vero Beach's ownership share.

Grand Gulf Nuclear Project – Assessed the adequacy of decommissioning funding and funding level for the grand Gulf Nuclear plant for Cooperative Energy. Project purpose was to assess changes in decommissioning funding rates and to determine if sufficient funds would be available for plant decommissioning.

Consumers Energy Midland Nuclear Plant – Responsible for overseeing EPC contractor design and construction of primary and secondary nuclear systems. Included review of systems for compliance with Nuclear Regulatory Commission regulations. Key projects included:

- Leading team to analyze plant and determine best methods for compliance with new CFR Appendix R Fire Protection rules
- Design of primary cooling system pump oil collection and disposal systems.
- Oversight of redesign of component cooling water systems.
- Analysis of diesel generator capability to meet emergency shutdown power requirements.
- Primary interface with Dow Chemical for steam supply contract.

Ohio Edison Company Erie Nuclear Project – Design engineer responsible for the design, equipment specifications, bid evaluations and regulatory licensing for nuclear steam supply system and ancillary systems. Key projects included:

- Project Thermal Analysis
- Development of NSS valve specifications
- Major equipment bid Proposal Evaluation and recommendations

Interface with Babcock & Wilcox on NSSS Design

RATES & REGULATORY

GDS associates, Inc. – Managing Director

North Dakota Public Service Commission Staff – Case No. PU-16-666 MDU Generatl Rate Case

Provided testimony on behalf of the North Dakota Public Service Commission Staff regarding return on equity, cost of capital, revenue requirement, and generation resource costs.

North Dakota Public Service Commission Staff – Case No. PU-15-96 NSP Determination of Prudence

Provided testimony on behalf of the North Dakota Public Service Commission Staff regarding analysis and recommendation concerning Northern States Power's ("NSP") need for additional generation resources.

Consumers Energy - Supervisor of Pricing and Forecasting

Managed the group responsible for setting and obtaining regulatory approval for the company's electric and gas rates. Developed new approaches to electric and natural gas competitive pricing, redesigned electric rates to simplify rates and eliminate losses and defined new strategies for customer energy pricing. Negotiated new electric supply contracts with key industrial electric customers resulting in over $800M in annual revenue. Testified in multiple regulatory proceedings.

EOS Energy Options & Solutions – Consulting Company

Provided testimony for multiple clients in both Detroit Edison and Consumers Energy in over 30 regulatory proceedings. Testimony topics included rates, public policy and deregulation. Also testified in several legislative proceedings in both Michigan and Ohio, addressing energy policy. Provided expert witness testimony in Massachusetts regarding wind energy projects.

NATURAL GAS COMBINED CYCLE EXPERIENCE

Consumers Energy – 1,560 MW Midland Cogeneration Venture
Member of a small team selected to investigate the feasibility of converting the mothballed Midland Nuclear Plant into a fossil fueled power plant. Established new plant configuration that repowered the existing nuclear steam turbine with natural gas fired combustion turbines and heat recovery steam generators. Developed the new thermal cycle and heat rate, determined how to supply steam to Dow chemical for cogeneration, developed models for projecting plant performance, defined which portions of the nuclear plant were useful in the new combined cycle plant and forecasted project economics.

Nordic Energy – Vice President

Project Manager for the development of two 1,150 MW IGCC projects proposed to Georgia Power and Xcel Energy in response to RFPs. Responsibilities included establishing thermal cycles, equipment selection, site selection, supervising engineering, developing project proforma and proposals.

Project Manager for 230 MW power barge to be located on the Columbia River near Portland Oregon. Lead the project development team responsible for securing equipment, designing the power plant, design of barges, assessing site feasibility, developing project economics and interconnection applications.

RENEWABLE ENERGY EXPERIENCE

Matinee Energy – Utility Scale Solar Developer

Engineering design and project development consultant for utility scale solar photovoltaic projects. Development activities include site selection, equipment specifications, financial analysis and preparation of proposals. Also responsible for engineering and securing electrical interconnection.

Windlab Developments USA – Wind Power Developer

Responsible for greenfield development of the US platform for wind energy projects east of the Mississippi. Developed the company's engineering protocol for wind project design and construction, responsible for managing engineering design and construction of projects, and established six wind power projects (750 MW). Responsible for negation of Power Purchase Agreements, electrical interconnection studies, interface with Midwest ISO and submitting Generation Interconnection Application.

TradeWind Energy - Wind Power Project Developer

Project developer for 800 MW of wind power projects in Michigan and Indiana. Introduced new project management methods to the development process which resulted in savings of over $200,000 annually on each project.

Third Planet Windpower – Wind Power Project Developer

Engineering and project management consultant to support the startup of new wind power company. Established engineering standards used for selection of wind project equipment and project construction, analysis tools for evaluating projecting wind project power production, and performed project economic modeling.

Noble Environmental Power – Wind Power Project Developer

Electric transmission system consultant on the development of several wind power projects. Supported Noble's decisions on transmission gird interconnect and negotiate interconnection agreements.

ENERGY EFFICIENCY EXPERIENCE

Arkansas Energy Office – Weatherization Assistance Program Evaluation

Evaluated the performance and operations of Arkansas's Weatherization Assistance Program. This included review of program effectiveness, program operations, energy efficiencies attained, adequacy of energy efficiency measures and subcontractor performance.

CLEAResult – Arkansas Energy Efficiency Programs

Energy efficiency operations and program support for 400% increase in Arkansas energy efficiency programs. Developed processes for data collection, field staff deployment and job assignments.

ECONOMIC IMPACT ASSESSMENT

Michigan Department of Environmental Quality - Economic Impacts of a Renewable Portfolio Standard and Energy Efficiency Program for Michigan

Project Manager for this report which focused on the economic impact of renewable portfolio standard and energy efficiency programs on the State of Michigan. The evaluation sued in this report encompassed using integrated resource planning models, econometric modeling and electric pricing models for the entire State of Michigan.

West Michigan Business Alliance - Alternative and Renewable Energy Cluster Analysis

Prepared the report provided a road map for Western Michigan businesses to establish new business in the renewable energy industry.

POWER PROJECT EXPERIENCE:

Detroit Edison St Clair Power Station – Performed coal combustion analysis associated with conversion Powder River Basin coal. Work included pulverizer mill performance testing, boiler combustion analysis on new coal, and unit performance analysis.

Consumers Energy Campbell 3 - Supported start-up efforts of this 800 MW pulverized coal power plant. Part of team that performed analysis of boiler data and determined the cause of superheater failure. Also part of team to analyze performance test data for warranty evaluation.

Consumers Energy Weadock Plant – Design oversight and specified various plant upgrades during major maintenance outage. Included replacement of high-pressure superheater, design of new steam supply pipes, valve specifications and supported plant restart.

GDS Associates, Inc
ENGINEERS & CONSULTANTS

Richard A. Polich, P.E.
Managing Director – Power Supply Services

PAPERS & PUBLICATIONS

Engineering and Economic Evaluation of Offshore Wind Plant Performance and Cost Data, 2011, Produced for the Electric Power Research Institute, KEMA, Inc.

FERC's 15% Fast Track Screening Criterion, 2012, Paper reviewing the FERC 15% screening criteria for electrical interconnection, KEMA, Inc.

Island of Saint Maarten Sustainable Energy Study, 2012, Produced for the Cabinet of Ministry VROMI, KEMA Inc.

A Study of Economic Impacts from the Implementation of a Renewable Portfolio Standard and an Energy Efficiency Program in Michigan, 2007, Produced for the Michigan Department of Environmental Quality

Alternative and Renewable Energy Cluster Analysis, 2007, Produced for the West Michigan Strategic Alliance and The Right Place

COURSES & SEMINARS

Association of Energy Engineers – Certified Energy Manager
Green Building Council – Associated LEED Certification Training
CLEAResult Leadership Academy

COMMUNITY SERVICE AND ACTIVITIES

Bicycling, hiking and cross-country skiing
Instrument-Rated Private Pilot
Habitat for Humanity
Scoutmaster
Soccer coach and referee
Volunteer work for disaster relief and building homes in Mexico

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 69
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-2

PREVIOUS TESTIMONY OF RICHARD A. POLICH

COMMISSION	CASE	ON BEHALF	TITLE
FERC	ER17-1821-002	Joint Customers	Revenue Requirement for Reactive Power Production Capability of the Panda Stonewall Generating Facility
North Carolina	E-2 Sub1142	Duke Energy Progress	Duke Energy Progress General Rate Case
Indiana	38707 FAC111-S1	Nucor Steel	Duke Energy Indiana, LLC for Fuel Cost Adjustment Clause
North Dakota	PU-16-166	ND PSC Staff	Montana-Dakota Utilities 2016 Electric Rate Increase Application
Hawaii	2015-0022	Sun Edison	Regarding the Hawaiian Electric Company, Inc. and NextEra Merger
North Dakota	PU-15-96	ND PSC Staff	Northern States Power Determination of Prudence
Michigan	U-10143	Consumers Energy	Consumers Energy Approval of an Experimental Retail Wheeling Case
Michigan	U-10335	Consumers Energy	General Rate Case
Michigan	U-10625	Consumers Energy	Proposal for Market-Based Rates Under Rate-K
Michigan	U-10685	Consumers Energy	1996 General Rate Case
Michigan	U-11915	Energy Michigan	Supplier Licensing
Michigan	U-11955	Energy Michigan	Consumers Energy Stranded & Implementation Cost Recovery
Michigan	U-11956	Energy Michigan	Detroit Edison Stranded & Implementation Cost Recovery
Michigan	U-12478	Energy Michigan	Detroit Edison Asset Securitization Case
Michigan	U-12488	Energy Michigan	Consumers Energy Retail Open Access Tariff
Michigan	U-12489	Energy Michigan	Detroit Edison Retail Open Access Tariffs
Michigan	U-12505	Energy Michigan	Consumers Energy Asset Securitization Cases
Michigan	U-12639	Energy Michigan	Stranded Cost Methodology Case
Michigan	U-13380	Energy Michigan	Consumers Energy 2000, 2001 & 2002 Stranded Cost Case
Michigan	U-13350	Energy Michigan	Detroit Edison 2000 & 2001 Stranded Cost Case
Michigan	U-13715	Energy Michigan	Consumers Energy Securitization of Qualified Costs
Michigan	U-13720	Energy Michigan	Consumers Energy 2002 Stranded Costs
Michigan	U-13808	Energy Michigan	Detroit Edison General Rate Case
Michigan	U-13808-R	Energy Michigan	Detroit Edison 2004 Stranded Cost & Assistance Credit for Residential Electric Customers

PREVIOUS TESTIMONY OF RICHARD A. POLICH

COMMISSION	CASE	ON BEHALF	TITLE
Michigan	U-14474	Energy Michigan	Detroit Edison 2004 PSCR Reconciliation Case
Michigan	U-13933	Energy Michigan	Detroit Edison Low-Income Energy Assistance Credit for Residential Electric Customers
Michigan	U-13917-R	Energy Michigan	Consumers Energy 2004 PSCR Reconciliation Case
Michigan	U-13989	Energy Michigan	Consumers Energy Request for Special Contract Approval

PREVIOUS TESTIMONY OF RICHARD A. POLICH

COMMISSION	CASE	ON BEHALF	TITLE
Michigan	U-14098	Energy Michigan	Consumers Energy 2003 Stranded Costs
Michigan	U-14148	Energy Michigan	Consumers Energy MCL 460.10d(4) Case
Michigan	U-14347	Energy Michigan	Consumers Energy General Rate Case
Michigan	U-14274-R	Energy Michigan	Consumers Energy 2005 PSCR Reconciliation Case
Michigan	U-14275-R	Energy Michigan	Detroit Edison Company 2005 PSCR Reconciliation Case
Michigan	U-14399	Energy Michigan	Detroit Edison Company Application for Unbundling of Rate
Michigan	U-14992	Energy Michigan	Power Purchase Agreement and for Other Relief in Connection with the sale of the Palisades Nuclear Power Plant and Other Asset

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 70
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-3

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 70
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-3

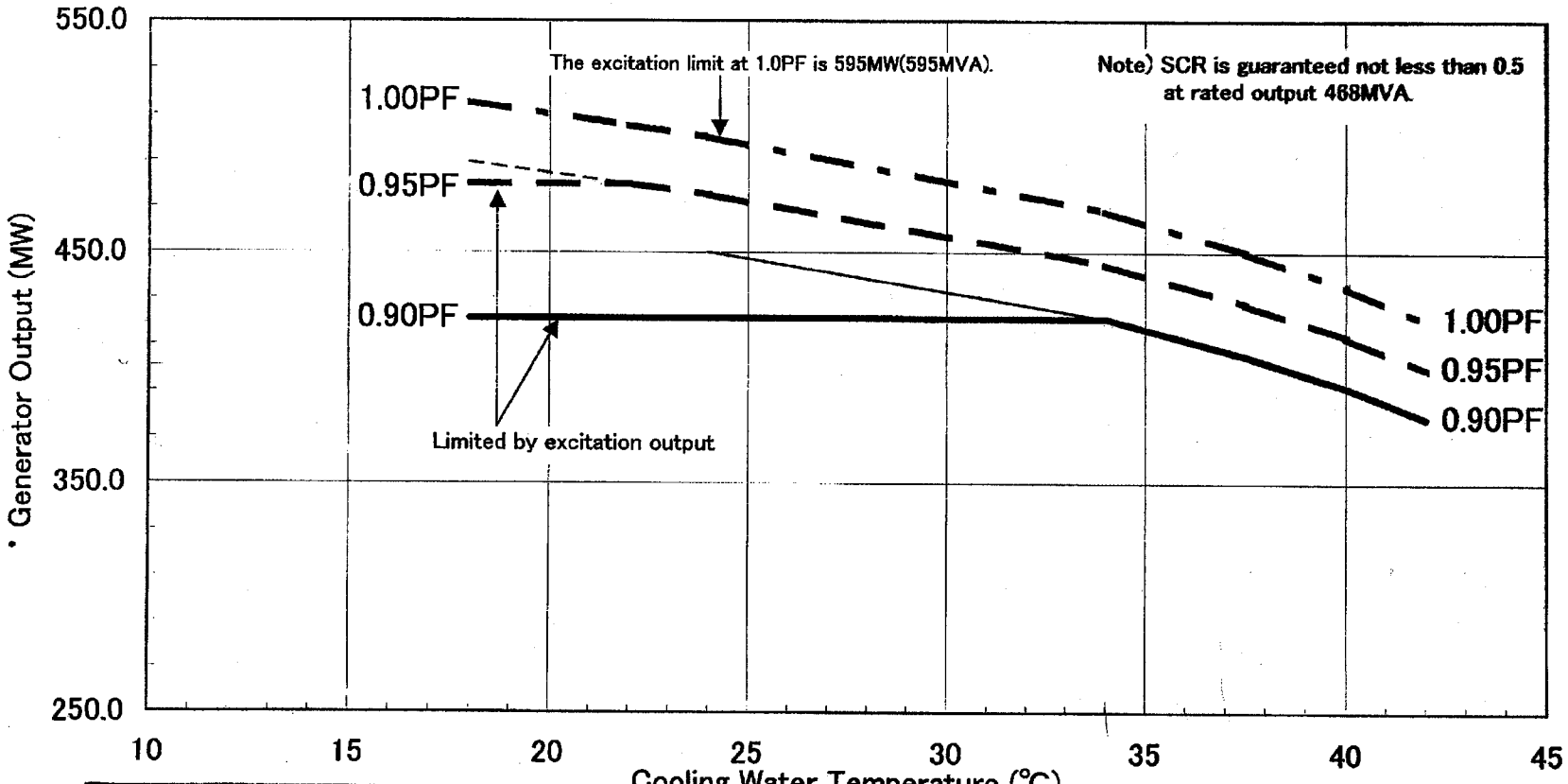
EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 71
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 71
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-4

KC917171

USA TENASKA C/C STEAM TURBINE GENERATOR
COOLING WATER TEMPERATURE VERSUS GENERATOR OUTPUT CURVE
(According to ANSI B temperature rise, Hydrogen gas pressure:0.50MPa-g)



APPROVED	H. Ohishi
CHECKED	T. Kawata
DESIGNED	'02-4/8 N. Arikawa S. Tomita

(Flesh Water and 34% Propylene Glycol Water)

The generator output curve shows only limitted by ANSI B temperature rise. The generator output may be also limitted by another functions. (i.e. SCR, cooling water condition, and so on.)

KC917171

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 72
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-5



Bartow Plant Operations History
Operation greater than 420 MW

Note: Data sampled every 10 minutes. Hours listed assumes value does not change for 10 mins.
*Maximum MW values are absolute values at a given sampled data point.
** Bad MW Data removed from time interval.

Month	Year	*Maximum Ouput - MW	Hours Operated Above Following MW						
			420	425	430	435	440	445	450
June	2009	404.3	0	0	0	0	0	0	0
July	2009	429.4	23.3	10.8	0	0	0	0	0
August	2009	429.2	27.2	5	0	0	0	0	0
September	2009	431.2	183.5	59.7	1.2	0	0	0	0
October	2009	438.2	190.7	155	44	25	0	0	0
November	2009	440.2	8	8	8	7	0.5	0	0
December	2009	426.1	0.5	0.5	0	0	0	0	0
January	2010	446.3	27.7	27.7	27.2	22.2	19.2	16.5	0
Feruary	2010	440.4	4.5	4.5	4.2	4	0.2	0	0
March	2010	444.4	56.7	55	43.3	19.2	9.2	0	0
April	2010	445.5	35.8	33.7	28.7	14.7	10.7	0.3	0
May	2010	439.9	67.2	65.7	34.7	0.2	0	0	0
June	2010	454.8	216.3	158	51	31	22.8	1.7	0.3
July	2010	447.1	117.3	116	112.7	95.3	43.5	6	0
August	2010	451.1	220.8	219	217	198.8	112	3.5	0.8
September	2010	446.6	182	180.8	179.5	174.8	102	4.3	0
October	2010	445.7	12	11.8	11.8	11.7	7.8	1.3	0
November	2010	358.5	0	0	0	0	0	0	0
December	2010	0	0	0	0	0	0	0	0
January	2011	452.1	3.2	2.5	1.8	1.8	1.8	0.7	0.2
Feruary	2011	415.4	0	0	0	0	0	0	0
March	2011	443.1	35.3	34.5	31.8	16	3.2	0	0
April	2011	457.6	294.7	290.2	287.3	273.8	185.5	40	0.3
May	2011	446.9	216.7	209.7	199.3	183.5	159.8	10.2	0
June	2011	449.8	180.2	177.5	176.2	174.7	147.5	9.5	0
July	2011	453.4	278.2	276.2	272.3	269.5	258.3	55.8	0.8
August	2011	449.5	317.2	314	306.3	292.5	267.8	45	0
September	2011	447.1	26.8	26.2	25.2	23	21	5	0
October	2011	448.5	118.5	117.2	115.3	106.8	69.7	13.5	0
November	2011	447.1	46.2	45.8	45.3	44.7	42	10.2	0
December	2011	449.2	4.2	4	4	3.7	3.5	0.8	0
January	2012	449.1	68.7	67.5	65.8	64.5	59.5	23.5	0
Feruary	2012	447.8	9.2	9	8.7	8.7	8	0.2	0
March	2012	0	0	0	0	0	0	0	0
April	2012	360.5	0	0	0	0	0	0	0
May	2012	400.6	0	0	0	0	0	0	0

June	2012	397.7	0	0	0	0	0	0	0
July	2012	396.9	0	0	0	0	0	0	0
August	2012	396.9	0	0	0	0	0	0	0
September	2012	397.9	0	0	0	0	0	0	0
October	2012	392.3	0	0	0	0	0	0	0
November	2012	375.8	0	0	0	0	0	0	0
December	2012	381.3	0	0	0	0	0	0	0
January	2013	369.4	0	0	0	0	0	0	0
Feruary	2013	379.3	0	0	0	0	0	0	0
March	2013	382.6	0	0	0	0	0	0	0
April	2013	372.8	0	0	0	0	0	0	0
May	2013	417.5	0	0	0	0	0	0	0
June	2013	420.5	0.2	0	0	0	0	0	0
July	2013	416.9	0	0	0	0	0	0	0
August	2013	405.8	0	0	0	0	0	0	0
September	2013	445.3	1.5	1.5	1.3	1.2	0.2	0.2	0
October	2013	405.3	0	0	0	0	0	0	0
November	2013	404	0	0	0	0	0	0	0
December	2013	411.1	0	0	0	0	0	0	0
January	2014	405.7	0	0	0	0	0	0	0
Feruary	2014	414.6	0	0	0	0	0	0	0
March	2014	403.5	0	0	0	0	0	0	0
April	2014	322.4	0	0	0	0	0	0	0
May	2014	2.5	0	0	0	0	0	0	0
June	2014	404.4	0	0	0	0	0	0	0
July	2014	399.1	0	0	0	0	0	0	0
August	2014	404.2	0	0	0	0	0	0	0
September	2014	407.5	0	0	0	0	0	0	0
October	2014	400.7	0	0	0	0	0	0	0
November	2014	356.2	0	0	0	0	0	0	0
December	2014	**452.5	16.3	10	8.8	7.5	3.6	3.1	1.5
January	2015	387.7	0	0	0	0	0	0	0
Feruary	2015	416.6	0	0	0	0	0	0	0
March	2015	295.8	0	0	0	0	0	0	0
April	2015	**421.1	0.2	0	0	0	0	0	0
May	2015	403.4	0	0	0	0	0	0	0
June	2015	425.6	0.2	0.2	0	0	0	0	0
July	2015	398.2	0	0	0	0	0	0	0
August	2015	398.4	0	0	0	0	0	0	0
September	2015	403.9	0	0	0	0	0	0	0
October	2015	330.4	0	0	0	0	0	0	0
November	2015	404.4	0	0	0	0	0	0	0
December	2015	400.8	0	0	0	0	0	0	0
January	2016	396	0	0	0	0	0	0	0
Feruary	2016	398.8	0	0	0	0	0	0	0
March	2016	396.8	0	0	0	0	0	0	0
April	2016	227.1	0	0	0	0	0	0	0

May	2016	**0	0	0	0	0	0	0	0
June	2016	421.2	1.2	0	0	0	0	0	0
July	2016	418.8	0	0	0	0	0	0	0
August	2016	422.4	0.7	0	0	0	0	0	0
September	2016	431.8	71.3	39	16.7	0	0	0	0
October	2016	431.1	4.3	4.2	0.8	0	0	0	0
November	2016	0	0	0	0	0	0	0	0
December	2016	402.1	0	0	0	0	0	0	0
January	2017	389.2	0	0	0	0	0	0	0
Feruary	2017	386.5	0	0	0	0	0	0	0
March	2017	309.5	0	0	0	0	0	0	0
April	2017	365.2	0	0	0	0	0	0	0
May	2017	372.1	0	0	0	0	0	0	0
June	2017	373.4	0	0	0	0	0	0	0
July	2017	372.8	0	0	0	0	0	0	0
August	2017	370.9	0	0	0	0	0	0	0
September	2017	369.6	0	0	0	0	0	0	0
October	2017	377.6	0	0	0	0	0	0	0
November	2017	366.5	0	0	0	0	0	0	0
December	2017	370.9	0	0	0	0	0	0	0
January	2018	358.9	0	0	0	0	0	0	0
Feruary	2018	341.9	0	0	0	0	0	0	0
March	2018	355.8	0	0	0	0	0	0	0
April	2018	354.7	0	0	0	0	0	0	0
May	2018	344.5	0	0	0	0	0	0	0
June	2018	319.8	0	0	0	0	0	0	0
July	2018	320.2	0	0	0	0	0	0	0
August	2018	349.3	0	0	0	0	0	0	0
September	2018	359.9	0	0	0	0	0	0	0
October	2018	370.6	0	0	0	0	0	0	0
November	2018	367.8	0	0	0	0	0	0	0
December	2018	308.3	0	0	0	0	0	0	0
January	2019	290.8	0	0	0	0	0	0	0
Feruary	2019	325.5	0	0	0	0	0	0	0
March	2019	272.9	0	0	0	0	0	0	0
April	2019	354.4	0	0	0	0	0	0	0
May	2019	347.9	0	0	0	0	0	0	0
June	2019	373.6	0	0	0	0	0	0	0
July	2019	365.5	0	0	0	0	0	0	0
August	2019	363.4	0	0		0	0	0	0
TOTALS ---------->			3068.5	2740.4	2330.2	2075.8	1559.3	251.3	3.9

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 73
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-6

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 73
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-6

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 74
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-7

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 74
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E.

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 75
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-8

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 75
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E.

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 76
PARTY: OFFICE OF PUBLIC COUNSEL – DIRECT
DESCRIPTION: Richard A. Polich, P.E. RAP-9

REPLACEMENT POWER COSTS
FOR BCC 40 MW DERATE

Line	Year	Month	Replacement Power Costs	Replacement MWh
	(a)	(b)	©	(d)
1	2017	4	$166,279	12,080
2	2017	5	$218,202	16,320
3	2017	6	$161,352	14,440
4	2017	7	$259,475	19,560
5	2017	8	$190,655	18,400
6	2017	9	$336,487	18,840
7	2017	10	$238,338	21,040
8	2017	11	$198,637	20,400
9	2017	12	$236,112	20,960
10	2018	1	$301,026	12,080
11	2018	2	$103,196	16,960
12	2018	3	$319,840	24,880
13	2018	4	$209,139	18,360
14	2018	5	$195,795	14,200
15	2018	6	$154,945	13,440
16	2018	7	$235,202	23,240
17	2018	8	$162,273	15,880
18	2018	9	$209,104	20,480
19	2018	10	$262,358	22,520
20	2018	11	$223,721	15,680
21	2018	12	$168,450	15,560
22	2019	1	$119,348	15,920
23	2019	2	$71,018	10,080
24	2019	3	$122,114	17,600
25	2019	4	$183,359	18,080
26	2019	5	$174,136	18,280
27	2019	6	$189,686	17,240
28	2019	7	$143,261	15,200
29	2019	8	$186,630	16,080
			Annual Totals	
30		2017	$2,005,536	162,040
31		2018	$2,545,049	213,280
32		2019	$1,189,552	128,480
33		2017 Outage	$11,100,000	
34		**Total**	**$16,840,136**	**503,800**

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

Auditor's Report

Tampa Electric Company
Hedging Activities

Twelve Months Ended July 31, 2019

Docket No. 20190001-EI
Audit Control No. 2019-070-2-2
August 01, 2019

Intesar Terkawi
Audit Manager

Linda Hill
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 77
PARTY: STAFF – (DIRECT)
DESCRIPTION: Intesar Terkawi IT-1

Table of Contents

Purpose 1

Objectives and Procedures 2

Audit Findings
None 4

Purpose

To: Florida Public Service Commission

We performed the procedures described later in this report to meet the objectives set forth by the Division of Accounting and Finance in its audit service request dated March 08, 2019. We applied these procedures to the schedules prepared by Tampa Electric Company in support of its filing for hedging activities in Docket No. 20190001-EI for the twelve months ended July 31, 2019.

The report is intended only for internal Commission use.

Objectives and Procedures

General

Definition

TECO or Utility refers to the Tampa Electric Company.

Accounting Treatment

Objective: The objective was to determine whether the accounting treatment for futures, options, and swap contracts between TECO and its counterparties is consistent with Commission Order No. PSC-2002-1484-FOF-EI, issued October 30, 2002, in Docket No. 20011605-EI, and as clarified by Order No. PSC-2008-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-2008-0667-PAA-EI, issued October 8, 2008, in Docket No. 20080001-EI.

Procedures: We obtained TECO's supporting detail of the hedging settlements for the months of August through November 2018. TECO's hedging activities ceased in the month of November 2018 due to the hedging moratorium. Support documentation for the four months was traced to the general ledger transaction detail. We verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

Objective: The objective was to determine whether the gains and losses associated with each financial hedging instrument that TECO implemented are in compliance with Commission Order Numbers PSC-2002-1484-FOF-EI, PSC-2008-0316-PAA-EI, and PSC-2008-0667-PAA-EI, relating to hedging activities.

Procedures: We traced the monthly balances of hedging transactions from TECO's Hedging Information Report to its Mark to Market Position Report for the period August 1, 2018, to November 30, 2018. We selected all gas hedging transactions for the four months and traced them from the Mark to Market Position Report to the third-party confirmation notices and contracts. We traced a sample of the purchase prices to the Gas daily NYMEX-Henry Hub gas futures contract rates. We traced the related settlements prices to the Gas Daily-NYMEX Henry Hub gas futures contract rate. We recalculated the gains and losses and traced them to the Utility's journal entries for realized gains and losses. We confirmed with the Utility that hedging transactions did not include tolling agreements. No exceptions were noted.

Hedged Volume and Limits

Objective: The objective was to determine whether the quantities of natural gas, residual fuel oil, and purchased power are hedged within the limits (percentage range) as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations. We also obtained TECO's analysis of the monthly percent of fuel hedged in relation to fuel burned for August through November 2018 and compared them to the Utility's Risk Management Plan filed in 2016. There has not been a Risk Management Plan filed subsequent as all such filings ceased as a result of the hedging moratorium effective December 5, 2016. No exceptions were noted.

Separation of Duties

Objectives: The objectives were to review TECO's procedures for separating duties related to hedging activities for Front Office, Middle Office, and Back Office and their internal and external auditors' workpapers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits specifically performed on the separation of duties related to hedging activities. No exceptions were noted.

Audit Findings

None

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

Auditor's Report

Duke Energy Florida, LLC
Hedging Activities

Twelve Months Ended July 31, 2019

Docket No. 20190001-EI
Audit Control No. 2019-070-2-1
August 23, 2019

Simon O. Ojada
Audit Manager

Linda Hill
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 78
PARTY: STAFF – (DIRECT)
DESCRIPTION: Simon O. Ojada SOO-1

Table of Contents

Purpose 1

Objectives and Procedures 2

Audit Findings
None 4

Purpose

To: Florida Public Service Commission

We performed the procedures described later in this report to meet the objectives set forth by the Division of Accounting and Finance in its audit service request dated March 8, 2019. We applied these procedures to the schedules prepared by Duke Energy Florida, LLC in support of its filing for hedging activities in Docket No. 20190001-EI for the twelve months ended July 31, 2019.

The report is intended only for internal Commission use.

Objectives and Procedures

General

Definition

DEF or Utility refers to Duke Energy Florida, LLC.

Accounting Treatment

Objective: The objective was to determine whether the accounting treatment for futures, options, and swap contracts between DEF and its counterparties is consistent with Commission Order No. PSC-2002-1484-FOF-EI, issued October 30, 2002, in Docket No. 20011605-EI, and as clarified by Order No. PSC-2008-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-2008-0667-PAA-EI, issued October 8, 2008, in Docket No. 20080001-EI.

Procedures: We obtained DEF's supporting detail of the hedging settlements for the 12 months ended July 31, 2019. The support documentation was reconciled to the general ledger transaction detail. We verified that the accounting treatment for hedging transactions and transaction costs is consistent with Commission orders relating to hedging activities. The Utility did not enter into any new contracts between August 1, 2018 and July 31, 2019. No exceptions were noted.

Gains and Losses

Objective: The objective was to determine whether the gains and losses associated with each financial hedging instrument that DEF implemented are in compliance with Commission Order Nos. PSC-2002-1484-FOF-EI, PSC-2008-0316-PAA-EI, and PSC-2008-0667-PAA-EI, relating to hedging activities.

Procedures: We reconciled the monthly balances of hedging transactions from DEF's Hedging Details Report for the period August 1, 2018, through March 31, 2019, to its Hedging Summary by Commodity Reports for 2018 and 2019. DEF completed its outstanding hedging transaction settlements as of March 31, 2019. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We selected 20 natural gas hedging transactions from September 2018 through December 2018 as a sample. We reconciled the selected samples from the Hedging Details Report to the third-party confirmation notices and contracts. We reconciled the gains and losses to the Utility's journal entries. We compared the price on the confirmation notice to the price published by the NYMEX Henry Hub gas futures contract rates. No exceptions were noted.

Hedged Volume and Limits

Objective: The objective was to determine whether the quantities of natural gas, residual fuel oil, and purchased power are hedged within the limits (percentage range), as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations for all hedged fuel types in compliance with the 2016 Risk Management Plan. There were no new hedging and Risk Management Plans in 2018 or 2019. No exceptions were noted.

Separation of Duties

Objectives: The objectives were to review DEF's procedures for separating duties related to hedging activities for Front Office, Middle Office, and Back Office, and the internal and external auditors' work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. We reviewed the Utility Audit Services Department's evaluations for the 12 months ended December 31, 2018, for the Regulated Fuels Inventory Management Process and the Regulated Trading Cycle. There were no external or internal audits on hedging activities during the test period. No exceptions were noted.

Audit Findings

None

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tallahassee District Office

Auditor's Report

Gulf Power Company
Hedging Activities

Twelve Months Ended July 31, 2019

Docket No. 20190001-EI
Audit Control No. 2019-070-1-1
August 21, 2019

Debra Dobiac
Audit Manager

Marisa N. Glover
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 79
PARTY: STAFF – (DIRECT)
DESCRIPTION: Debra Dobiac DMD-1

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Purpose 1

Objectives and Procedures 2

Audit Findings
None 4

Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the objectives set forth by the Division of Accounting and Finance in its audit service request dated March 8, 2019. We have applied these procedures to the attached schedules prepared by Gulf Power Company in support of its filing for hedging activities in Docket No. 20190001-EI.

The report is intended only for internal Commission use.

Objectives and Procedures

Definitions

GPC or Utility refers to Gulf Power Company

Accounting Treatment

Objectives: The objective was to determine whether the accounting treatment for futures, options, and swap contracts between GPC and its counterparties is consistent with Commission Order No. PSC-2002-1484-FOF-EI, issued October 30, 2002, in Docket No. 20011605-EI, and as clarified by Order No. PSC-2008-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-2008-0667-PAA-EI, issued October 8, 2008, in Docket No. 20080001-EI.

Procedures: We obtained GPC's supporting detail of the hedging settlements for the twelve months ended July 31, 2019. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. Pursuant to the 2017 Stipulation and Settlement Agreement, the Utility did not enter into any new contracts between August 1, 2018 and July 31, 2019. GPC's hedge program is expected to be completed in the first quarter of 2020. No exceptions were noted.

Gains and Losses

Objectives: The objective was to determine whether the gains and losses associated with each financial hedging instrument that GPC implemented are in compliance with Commission Order Nos. PSC-2002-1484-FOF-EI, PSC-2008-0316-PAA-EI, and PSC-2008-0667-PAA-EI relating to hedging activities.

Procedures: We traced the monthly balances of all hedging transactions from GPC's Hedging Information Reports to its settlement report and its general ledger for the period August 1, 2018 to July 31, 2019. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the NYMEX Henry Hub gas futures contract rates. We compared these recalculated gains and losses with GPC's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

Objectives: The objective was to determine whether the quantities of natural gas, residual oil, and purchased power are hedged within the limits (percentage range), as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations. We also obtained GPC's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the

twelve months ended July 31, 2019, and compared them with the Utility's 2016 Risk Management Plan. No exceptions were noted.

Separation of Duties

Objectives: The objectives were to review GPC's procedures for separating duties related to hedging activities for Front Office, Middle Office, and Back Office and internal and external audit reports or work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. We noted that the hedges currently in place for GPC were previously executed by Southern Company. As of January 1, 2019, all hedges were transferred to Next Era/FPL employees and they will oversee the settling of those hedges. There were no internal or external audits specifically performed on the separation of duties related to hedging activities. No further work was performed.

Audit Findings

None

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 80
PARTY: Duke Energy Florida
DESCRIPTION: Rebuttal /Jeffrey Swartz JS-2

Executive Summary

Over the past 3 plus years, Duke Energy Florida LLC (Duke), at times working independently and at times together with Mitsubishi Hitachi Power Systems (MHPS), undertook a root cause analysis (RCA) of the cause(s) for the Unit 4S L-0 blade cracks and failures that occurred during normal station operations at Bartow Station.

[redacted]



Historical Overview

Bartow is a 4x1 CC Station with a steam turbine (ST) manufactured by MHPS. The ST was purchased from Tenaska Power Equipment, LLC (Tenaska) which intended to use it for a 3x1 CC with a gross output of 420MW. The ST was never delivered to Tenaska and remained with MHPS in a warehouse in Japan until Duke purchased the unit in 2006.



Before the ST was purchased by Duke, Duke contracted with MHPS to evaluate the ST design conditions and to update heat balances for a 4x1 CC configuration. MHPS updated the heat balances for use in a 4x1 CC configuration. CC units blend steam from the combustion turbines (CT) as they start-up and/or shut-down with steam to the ST. These blending events, which are a common occurrence for CC units, result in brief periods of higher steam temperatures and flows into the condenser near the ST L-0 blades.

Since commissioning of the Bartow ST in 2009, there have been five (5) events involving L-0 blade failures and/or replacements as described, below.

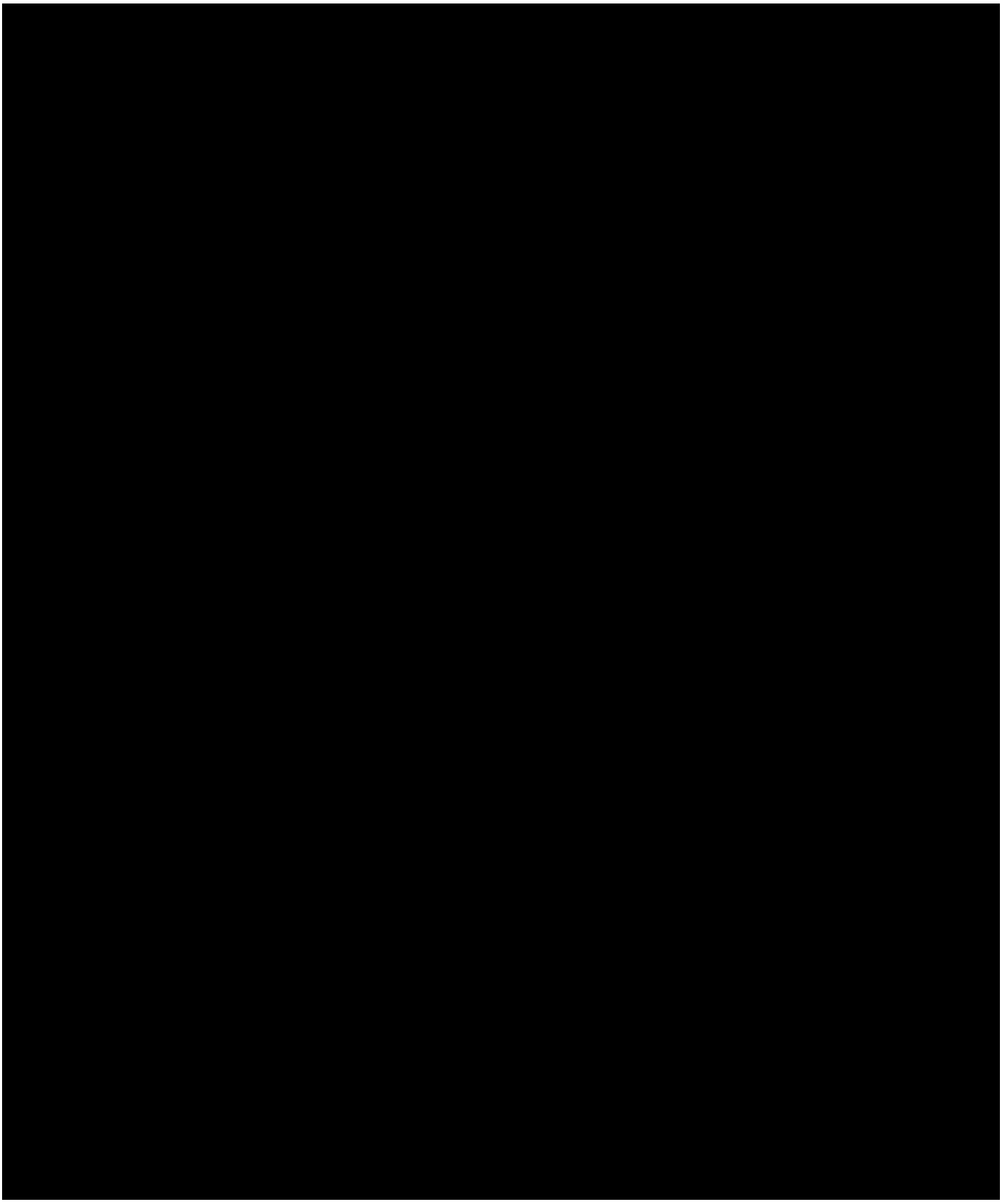
Each 40" MHPS steel blade is twisted with a "root end" that connects it to the hub, a snubber at the mid-point or mid-span, and a shroud with airfoil tips at the top. While the ST spins up to its operating speed of 3600rpm, each blade elongates and starts to untwist. The snubbers and airfoil tips are designed to contact each other and create a stabilizing central and outer ring.

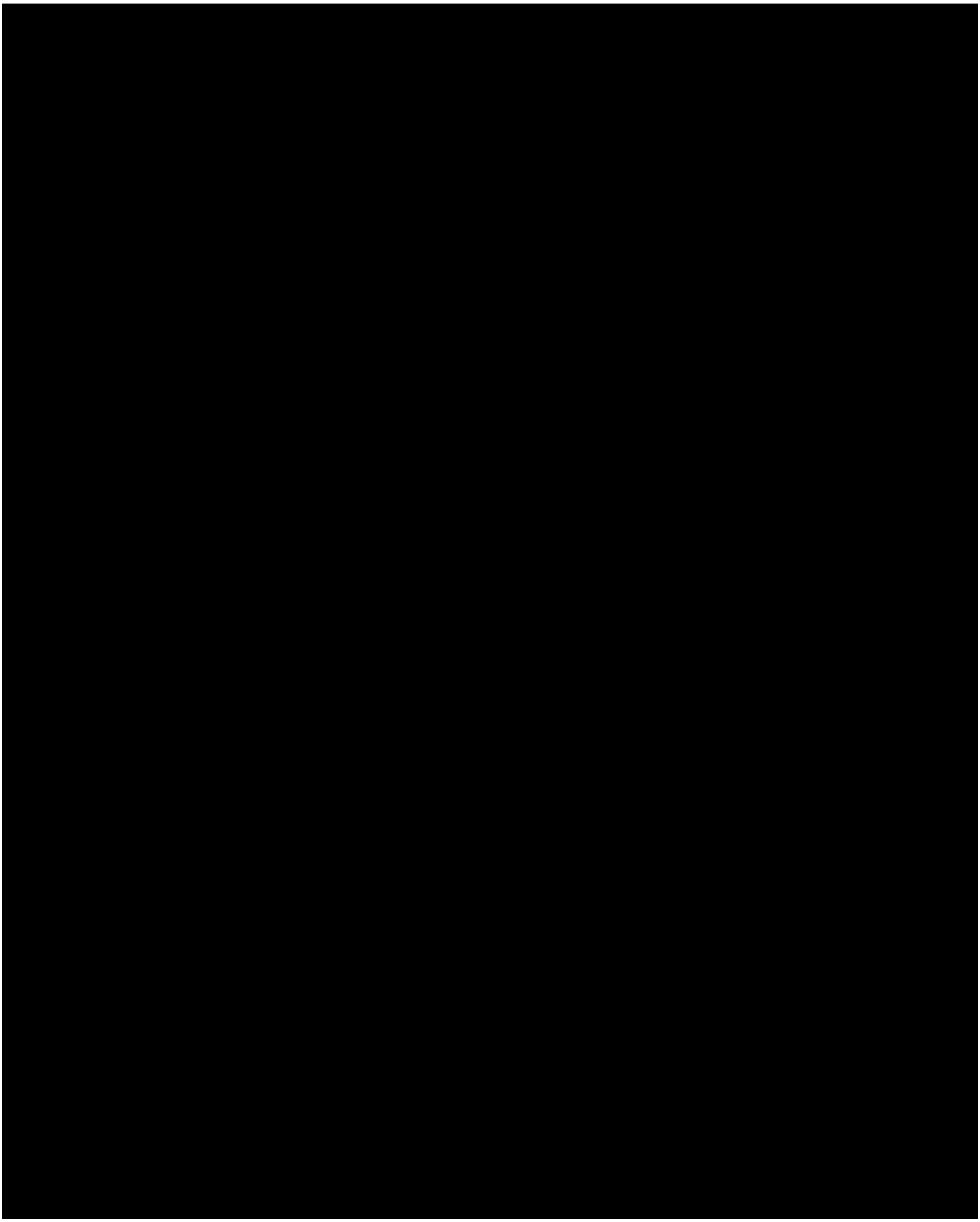
[redacted]

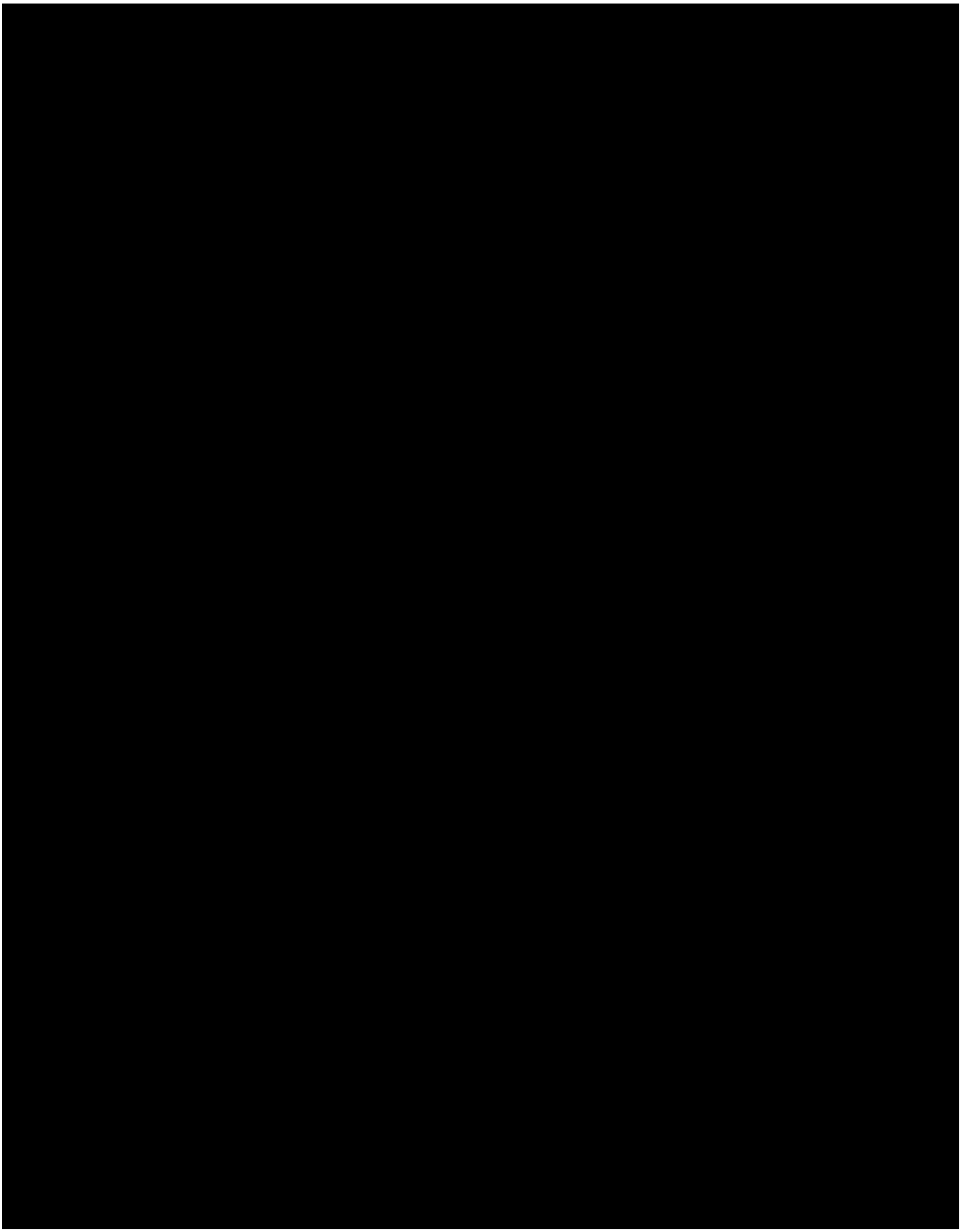
Table A: Bartow L-0 Events Summary

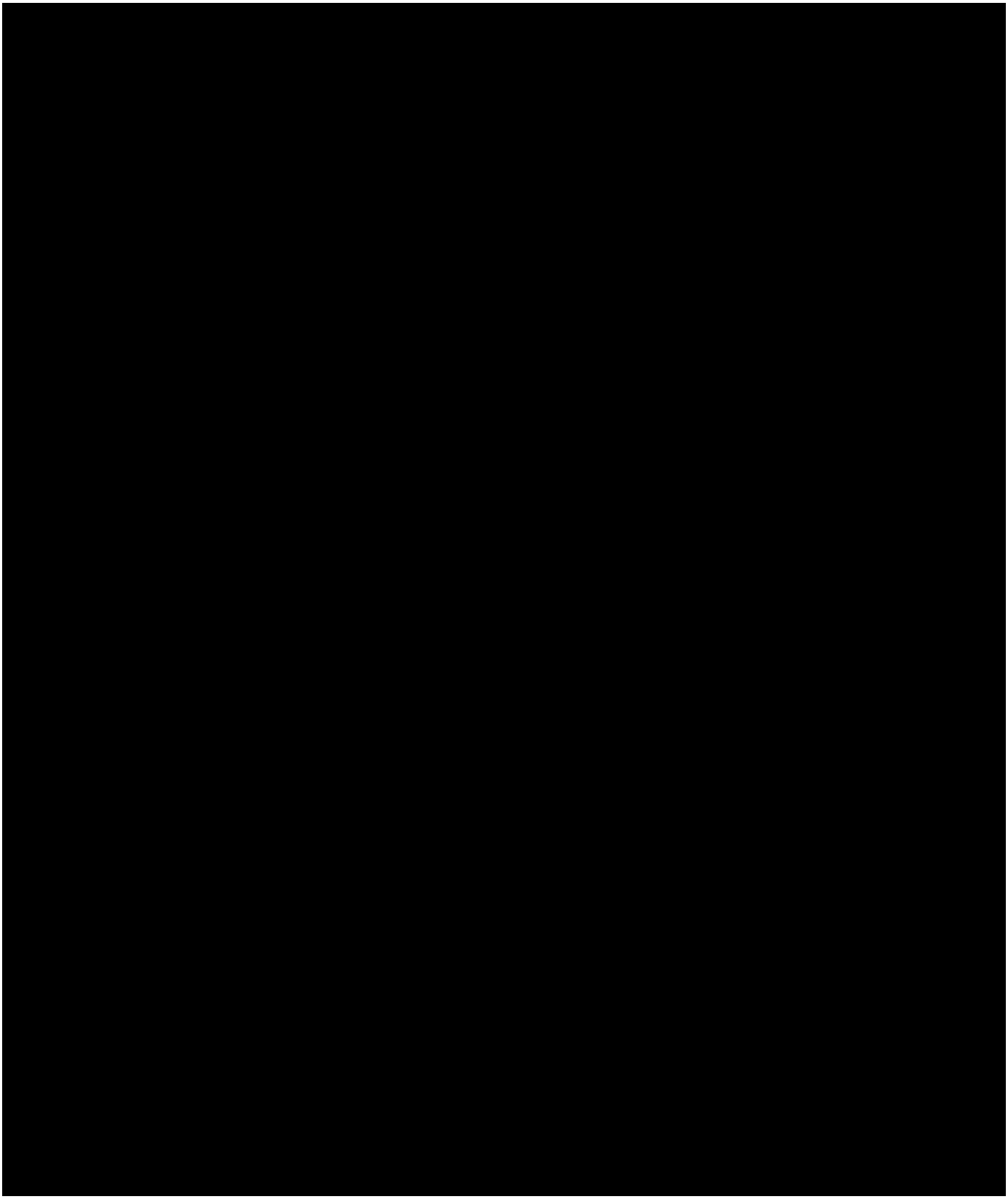
	Period 1	Period 2	Period 3	Period 4	Period 5
Date	June 2009 to March 2012	April 2012 to August 2014	December 2014 to April 2016	May 2016 to Oct 2016	December 2016 to February 2017
Service Duration	~34 Months	~28 Months	~17 Months	~5 Months	~2 Months
[redacted]					
Information Shared with MHPS	Duke provided all requested PI data.	Duke provided all requested PI data.	Duke provided all requested PI data.	Duke provided all requested PI data.	Duke provided all requested PI data.

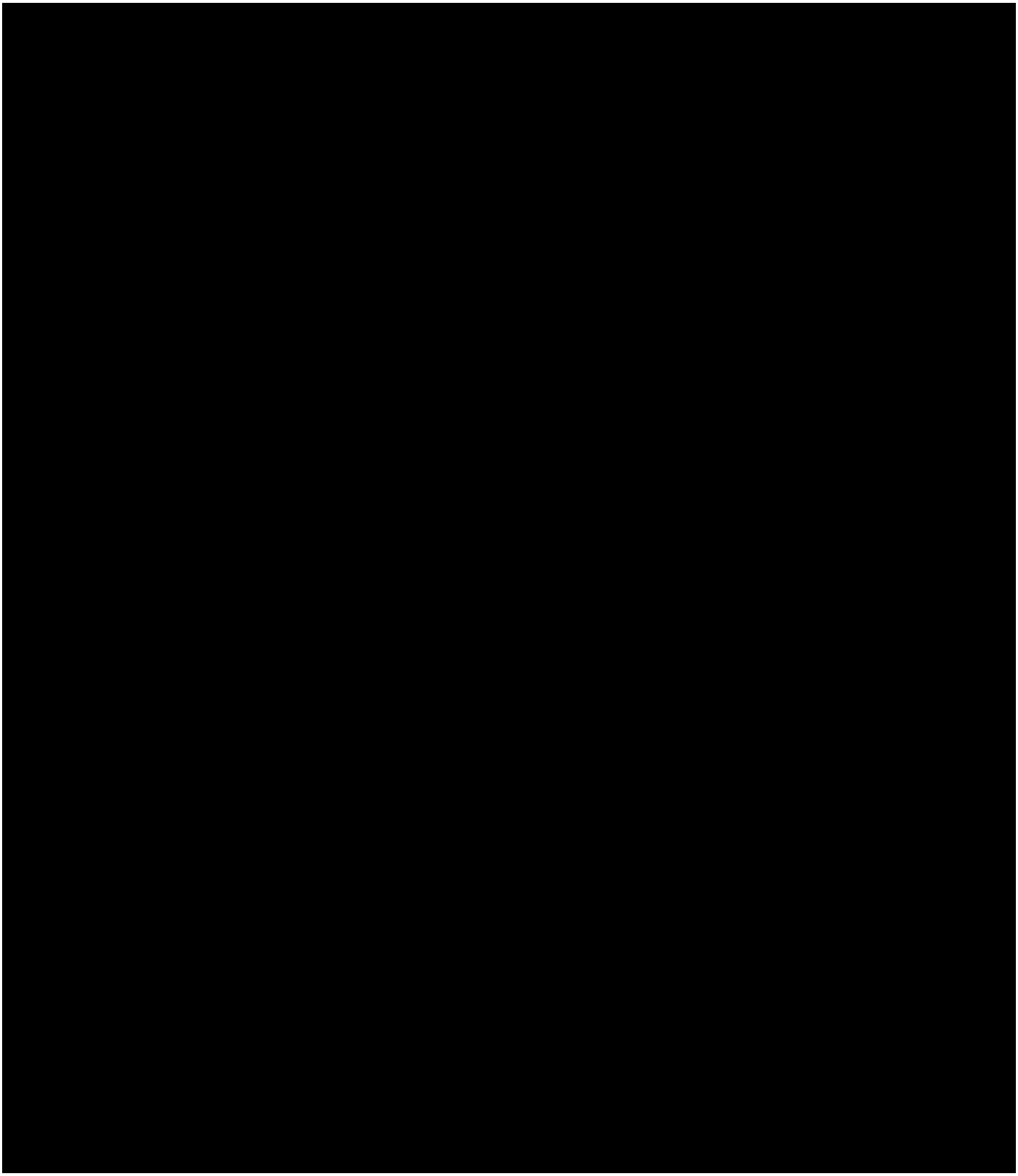
[redacted]

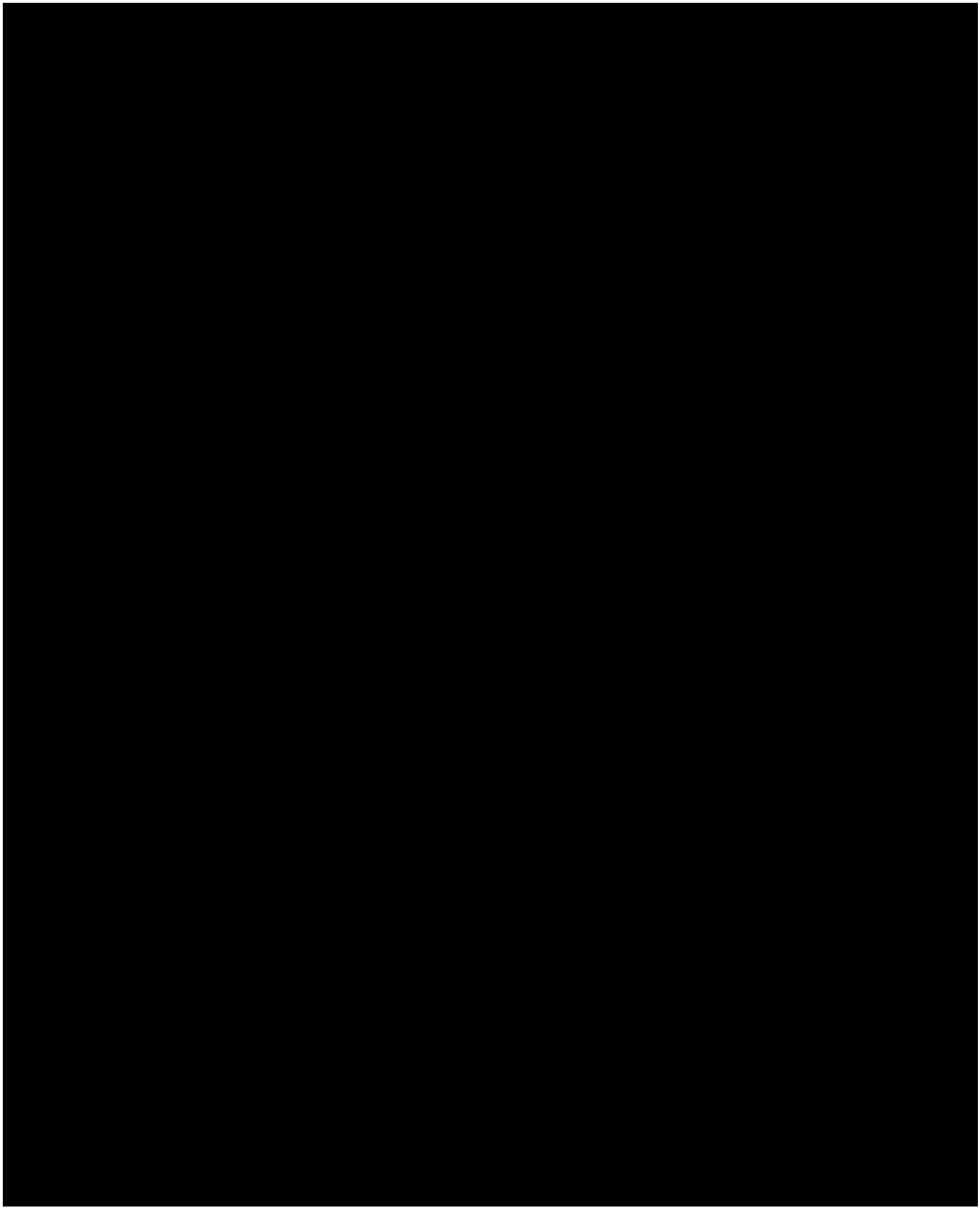


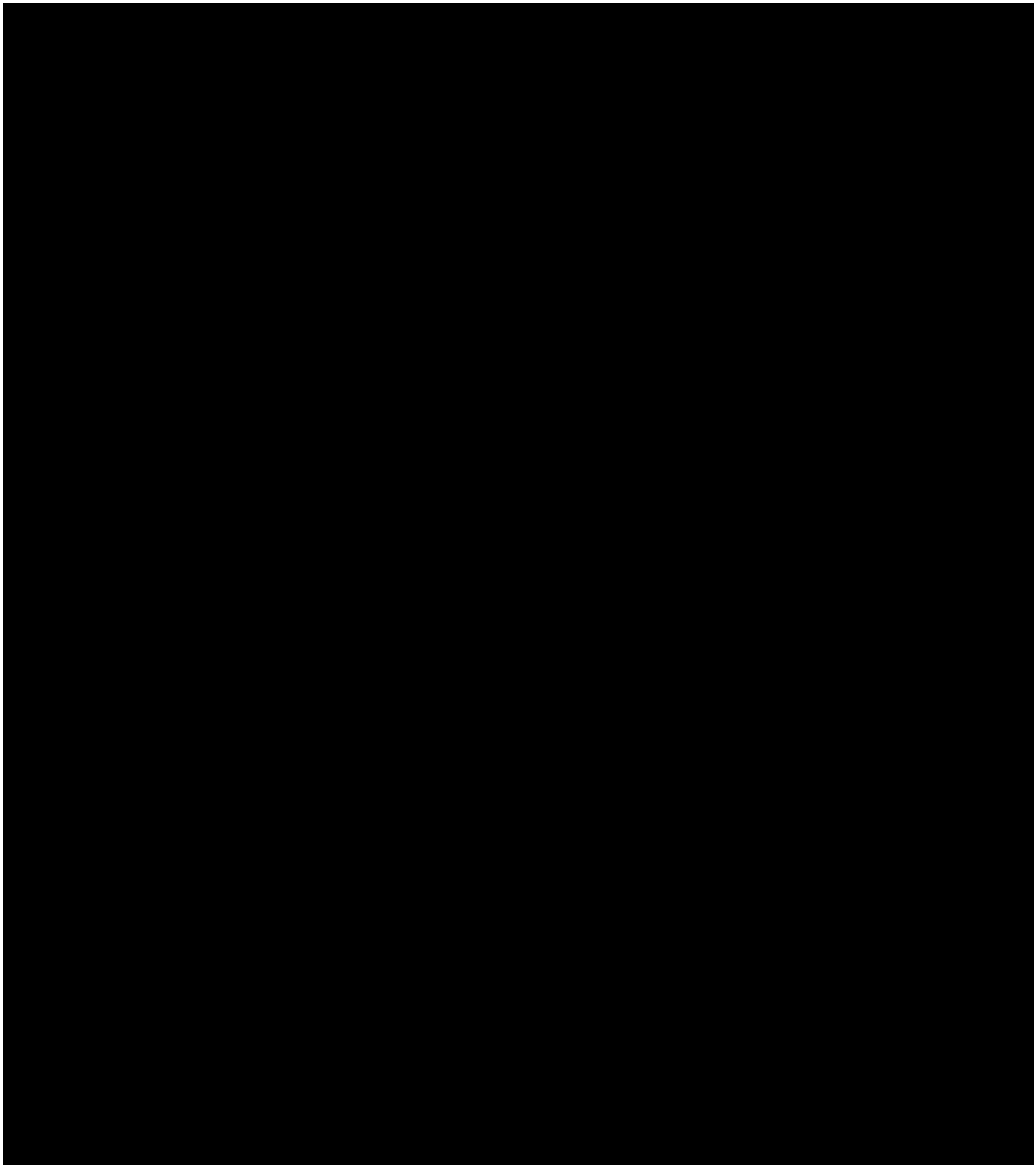




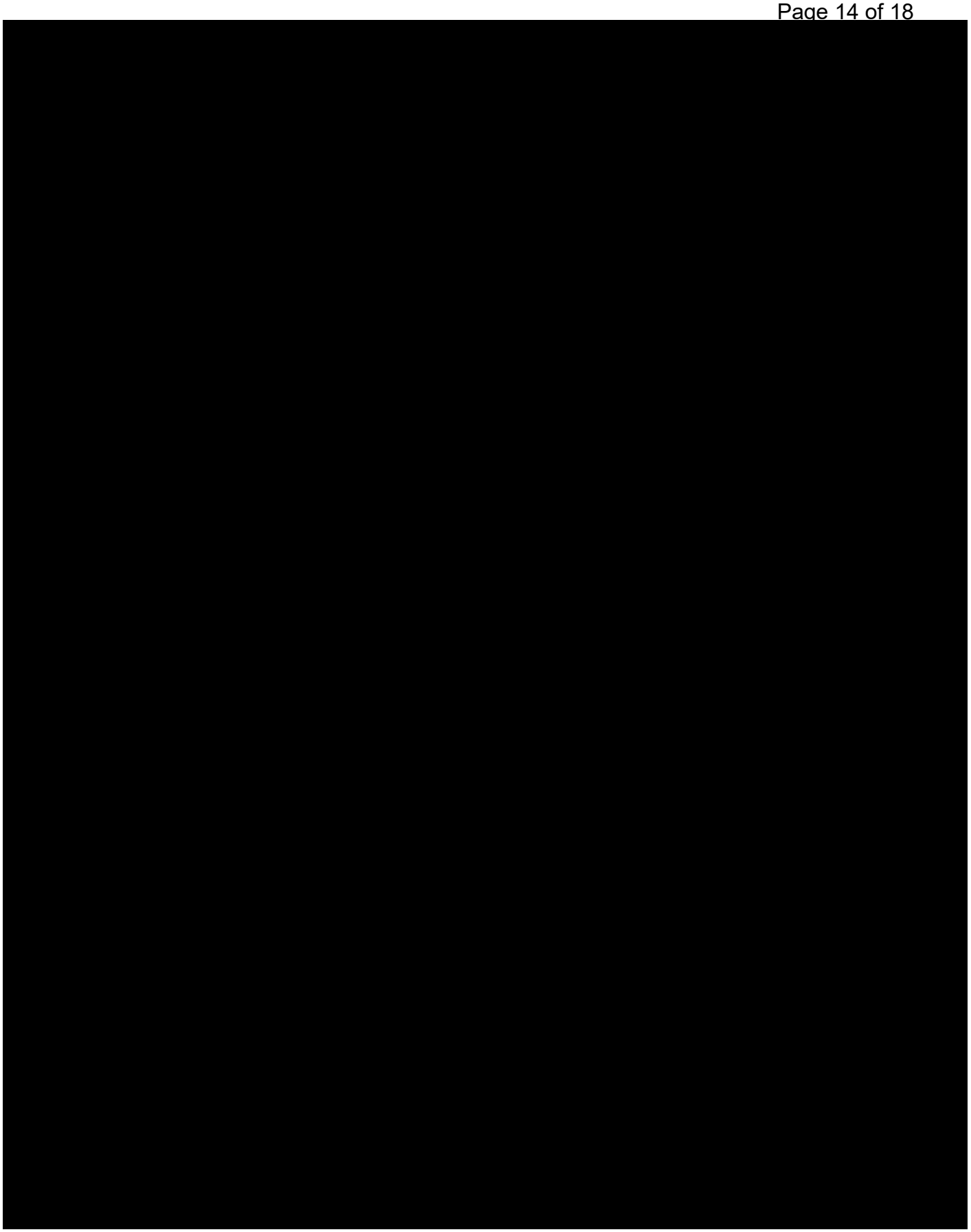














CONCLUSION:



[redacted] This RCA report is Duke's product and presents its view of the root cause based on all inputs received.





EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT:81
PARTY: Duke Energy Florida
DESCRIPTION: Rebuttal/Jeffrey Swartz JS-3

Docket No. 20190001
Duke Energy Florida
Witness: Swartz
Exhibit No. ___(JS-3)

REDACTED

Pages 1 through 22 are confidential in their entirety.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 81
PARTY: DUKE ENERGY FLORIDA – (REBUTTAL)
DESCRIPTION: Jeffrey Swartz JS-3

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 82
PARTY: Duke Energy Florida (Rebuttal)
DESCRIPTION: Jeffrey Swartz JS-4

Docket No. 20190001
Duke Energy Florida
Witness: Swartz
Exhibit No. ___(JS-4)

REDACTED

Pages 1 through 35 are confidential in their entirety.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 82
PARTY: DUKE ENERGY FLORIDA – (REBUTTAL)
DESCRIPTION: Jeffrey Swartz JS-4

83

FPL's Response to Staff's First Set of Interrogatories, Nos. 1-8

CONFIDENTIAL DN. 03165-2019

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 83
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Gerald J. Yupp (1-7) Renae B. Deaton (8)

QUESTION:
For each Request for Proposal (RFP) for coal issued in 2018 by or on behalf of FPL, list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

RESPONSE:
In 2018, FPL's coal fired generation consisted of the St. Johns River Power Park (SJRPP), Indiantown Co-Generation Plant and Scherer Unit 4.

In 2018, there were no RFPs issued for coal at SJRPP or Indiantown.

Coal is delivered to Plant Scherer exclusively by rail in unit trains of approximately 135 cars. The route of delivery is a two-line haul via the BNSF Railway Company and Norfolk Southern (NS) trackage. BNSF services mines in the Powder River Basin (PRB) of Montana and Wyoming where the coal purchased for Scherer is produced. BNSF transports the coal to Memphis, TN for interchange with NS which then delivers the coal to Plant Scherer near Juliette, GA.

February Spot RFP for April-June 2018 Delivery

Supplier	Tonnage Bid (tons/month)	Coal Quality (Btu/lb.)	Delivered Price ($/MMBtu)
[redacted]	900,000	8350	2.347
	1,425,000	8400	2.361
	1,425,000	8300	2.383
	1,425,000	8500	2.399
	600,000	8425	2.399
	1,425,000	8550	2.432
	450,000	8600	2.45
	712,500	8900	2.461
	100,000	8850	2.472
	712,500	8700	2.544
	712,500	8800	2.591

May Spot RFP for July-September 2018 Delivery

Supplier	Tonnage Bid (tons/month)	Coal Quality (Btu/lb.)	Delivered Price ($/MMBtu)
[redacted]	600,000	8350	2.364
	1,800,000	8400	2.369
	1,800,000	8300	2.4
	1,800,000	8500	2.415
	600,000	8425	2.416
	600,000	8350	2.425
	1,800,000	8550	2.433
	300,000	8850	2.433
	900,000	8900	2.446
	150,000	8600	2.451
	900,000	8700	2.529
	900,000	8800	2.576

September Spot RFP for October-December 2018 Delivery

Supplier	Tonnage Bid (tons/month)	Coal Quality (Btu/lb.)	Delivered Price ($/MMBtu)
[redacted]	900,000	8400	2.385
	600,000	8350	2.387
	900,000	8500	2.428
	600,000	8425	2.451
	300,000	8850	2.46
	900,000	8600	2.468
	900,000	8900	2.48
	450,000	8900	2.483
	450,000	8700	2.502
	450,000	8800	2.519

November Spot RFP for January-March 2019 Delivery

Supplier	Tonnage Bid (tons/month)	Coal Quality (Btu/lb.)	Delivered Price ($/MMBtu)
[redacted]			

May Long Term RFP for Delivery in 2019, 2020, 2021 & 2022

Supplier	Year	Tonnage Bid (Total tons)	Coal Quality (Btu/lb.)	Delivered Price ($/MMBtu)
[redacted]				

Supplier	Year	Tonnage Bid (Total tons)	Coal Quality (Btu/lb.)	Delivered Price ($/MMBtu)
[redacted]				

Supplier	Year	Tonnage Bid (Total tons)	Coal Quality (Btu/lb.)	Delivered Price ($/MMBtu)
[redacted]				

September Long Term RFP for Delivery in 2019, 2020, 2021 & 2022

Supplier	Year	Tonnage Bid (Total tons)	Coal Quality (Btu/lb.)	Delivered Price ($/MMBtu)
[redacted]				

Supplier	Year	Tonnage Bid (Total tons)	Coal Quality (Btu/lb.)	Delivered Price ($/MMBtu)
[redacted]				

QUESTION:
Please describe the action taken for each bid identified in response to Interrogatory No. 1. Include in your response an explanation of the evaluation process and how successful proposals were selected.

RESPONSE:
Bids to supply spot coal to Scherer are evaluated on the basis of delivered cost. Regarding the February RFP for April - June 2018 delivery of spot coal, FPL elected to make no purchases. Regarding the May RFP for July - September 2018 FPL elected to purchase approximately 426,600 tons from Buckskin, the low evaluated bidder. Regarding the September RFP for October - December 2018 FPL elected to purchase approximately 425,595 tons from Buckskin, the low evaluated bidder. FPL also elected to purchase 66,356 tons from Buckskin based on the September RFP pricing matrix for November-December 2018, due to additional projected needs.

[redacted]

Bids to supply long-term coal to Scherer are evaluated on an NPV basis. Regarding the May RFP for delivery of long-term coal in 2019 through 2022, FPL elected to make no purchases.

[redacted]

QUESTION:
During 2018, did FPL experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.

RESPONSE:
FPL did not experience any transportation constraints for coal deliveries in 2018.

At Scherer during the normal course of railroad operations, the Plant Co-Owners, including FPL, incurred the following Locomotive Lease & Detention Charges in accordance with the Transportation Contract with Norfolk Southern:

Quarter Incurred	Charge Type	Total Charge	FPL (19.09%)
First	Detention	$272,051.50	$51,934.63
Second	Detention	$259,983.05	$49,630.76
Third	Detention	$833.76	$159.16
Third	Locomotive Lease	$10,280.00	$1,962.45
Fourth	Locomotive Lease	$129,920.00	$24,801.73

QUESTION:
For each RFP for natural gas issued in 2018 by FPL, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline used for delivery.

RESPONSE:
FPL did not issue any RFPs for natural gas purchases during 2018. FPL contacts multiple suppliers and/or brokers to discuss pricing, terms, and volumes when making procurement decisions. This information is used by FPL personnel to determine the appropriate supply portfolio.

QUESTION:
Please describe the action taken for each bid identified in response to Interrogatory No. 4. Include in your response an explanation of the evaluation process and how successful proposals were selected.

RESPONSE:
N/A. Please see FPL's response to Staff's First Set of Interrogatories, No. 4.

QUESTION:
In 2018, did FPL participate in any capacity discussions or bid for any firm pipeline capacity during "open season?" Please explain your response and identify the pipeline companies.

RESPONSE:
During the normal course of business, FPL participated in general capacity discussions with various pipeline companies throughout 2018. Those pipeline companies included firms such as Boardwalk Partners (Gulf South, Gulf Crossing), Kinder Morgan (Sonat, Tennessee, MidContinent Express), ETC (FGT), Enbridge (SESH, TETCO), Williams (Transco), Destin Pipeline, and Enable. These discussions did not lead to the purchase of any additional pipeline capacity in 2018.

QUESTION:
In 2018, did FPL participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

RESPONSE:
Yes, in the normal course of business, FPL participated in natural gas storage capacity discussions with Bay Gas Storage, Southern Pines Storage, and Petal Gas Storage, LLC. FPL entered into a new one-year transaction with Southern Pines Storage for 1 Bcf of natural gas storage capacity to diversify its storage portfolio.

QUESTION:
For the purpose of this interrogatory, please refer to FPL's December 2018 A Schedule filing, and specifically to Schedule A2, Line 13 (End of Period True Up amounts), Columns 7-9 for Year-To-Date amounts. Please explain the discrepancy between the actual and projected amounts, including in your response the primary reason(s) for the under-recovered balance.

RESPONSE:
Please refer to the 2018 Final True-Up testimony of FPL witness Renae Deaton, pages 5 through 11, filed in this Docket on March 1, 2019, for detailed explanations on the primary reasons for the variances between actual and projected amounts.

The net under-recovery of $70.6 million consists of an increase in jurisdictional fuel costs of $136.1 million (total fuel costs of $156.9 million) partially offset by an increase in revenues of $65.5 million.

The increase in total fuel costs and net power transactions is primarily due to a:

- $184.6 million increase in Fuel Cost of System Net Generation
- $0.7 million increase in Rail Car Lease (Cedar Bay/ICL/SJRPP)
- $0.3 million decrease in Variable Power Plant O&M Avoided due to Economy Purchases
- $0.2 million increase in Variable Power Plant O&M Attributable to Off-System Sales

This amount is offset by:

- $13.4 million decrease in Energy Cost of Economy Purchases
- $8.5 million increase in Fuel Cost of Power Sold
- $2.6 million increase in Gains from Off-System Sales
- $2.3 million increase in Fuel Cost of Stratified Sales
- $1.4 million decrease in Fuel Cost of Purchased Power
- $0.4 million decrease in Energy Payments to Qualifying Facilities

The increase in jurisdictional revenues was primarily due to jurisdictional sales that were 2,231,289 MWh higher than the actual/estimated projection.

DECLARATION

I sponsored the answers to Interrogatory Nos. 1 through 7 from **STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-8)** to Florida Power & Light Company in Docket No. 20190001-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: 3/18/19

DECLARATION

I sponsored the answer to Interrogatory No. 8 from **STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-8)** to Florida Power & Light Company in Docket No. 20190001-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.

Renae B. Deaton

Date: 14 March 2019

84

FPL's Response to Staff's Second Set of Interrogatories, Nos. 9-17

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 84
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Gerald J. Yupp (9-16) Renae B. Deaton (17)

QUESTION:
Please describe the steps the Company undertook to prepare the fuel price forecast the Company prepared to support its 2019 projections, as filed on August 24, 2018, in Docket No. 20180001. Discuss in your response when these steps were started and when these steps were concluded, and how the timeline for preparing this forecast compared to the timeline for preparing the similar forecasts for 2017 or 2018.

RESPONSE:
Developing the fuel price forecast that is used to prepare the annual Projection filing is typically a one-day process. The process involves gathering the latest projections (i.e., forward curve prices) from all data sources and updating fixed and variable costs associated with natural gas transportation and/or storage. FPL utilized forward curve prices from the close of business on July 27, 2018 for its 2019 projection filing, which was the most current information that could be incorporated into FPL's schedule for calculating the 2019 FCR factors. This methodology was also used to develop FPL's fuel price forecasts in both 2018 and 2017. FPL utilized forward curve prices from the close of business on July 28, 2017 for its 2018 projection filing and forward curve prices from the close of business on August 1, 2016 for its 2017 projection filing.

QUESTION:
How often are fuel price forecasts prepared? Discuss in your response what triggers, or market observations would prompt the Company to update its fuel price forecast.

RESPONSE:
As part of its routine business processes, FPL prepares a fuel price forecast on a monthly basis. This forecast is based on market prices from the close of business on the first Monday of each month (moved to Tuesday closing prices if the first Monday of the month is a holiday). For fuel filings (Actual/Estimated or Projection), if the fuel price forecast from the first Monday of the month does not allow adequate time to prepare the filing, FPL will prepare an additional forecast to accommodate the timing requirements. Given the frequency (monthly) of FPL's fuel price forecast updates, the necessity to produce an intra-month forecast based on market observations would be extremely rare.

QUESTION:
If known, identify the date the next fuel price forecast is scheduled to be prepared.

RESPONSE:
In accordance with FPL's response to Interrogatory No. 10, the next fuel price forecast will be prepared on April 2, 2019, using forward curve prices from the market close on April 1, 2019.

QUESTION:
Please identify the forecasting sources that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

RESPONSE:
FPL utilizes information from three external sources when developing the fuel price forecast prepared to support the Company's 2019 Projection Filing. J.D. Energy, Inc. provided coal and coal transportation forecast data. The Chicago Mercantile Exchange (CME) provided NYMEX forward commodity prices. The InterContinental Exchange (ICE) provided physical location price differentials used to develop the physical location delivered curves used when forecasting natural gas prices. Fixed and variable costs for natural gas transportation and/or storage are based on contractual terms and tariff rates.

QUESTION:
Were any of the sources identified in the response to Interrogatory number 12 new or different than the sources used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

RESPONSE:
No.

QUESTION:
Please identify the forecasting assumptions that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

RESPONSE:
FPL's fuel price forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve) for natural gas projections and Over-The-Counter ("OTC") forward market prices for light and heavy fuel oil projections. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the short-term are incorporated into the curves at all times. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy, Inc., a coal consulting firm. Projections for natural gas basis differentials are provided by the InterContinental Exchange (ICE). Each of these data sources is industry recognized, authoritative and independent. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. Fixed and variable costs for natural gas transportation and/or storage are based on contractual terms and tariff rates.

QUESTION:
Were any of the assumptions identified in the response to Interrogatory number 14 new or different than the assumptions used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

RESPONSE:
No.

QUESTION:
Discuss how the Company incorporates recognized, authoritative independent forecasts into its fuel price forecasts.

RESPONSE:
Please see FPL's response to Interrogatory No. 14.

QUESTION:
Please refer to the Company's January 2019 A-Schedule filing, and specifically to Schedule A-1, Line 24, reporting Transmission and Distribution (T & D) Losses.
a. Please show the mathematical inputs and/or the calculations that were performed in order to produce the dollar values (shown in Columns 3-5) for T & D Losses in this period.
b. An actual dollar value of $12,749,214 for T & D Losses was recorded in Column 3 for this period. Please explain the variance shown between the recorded dollar value for T & D Losses and the estimated dollar value for T & D Losses in this period.
c. Please show the mathematical inputs and/or the calculations that were performed in order to produce the quantity of megawatt-hours (shown in Columns 7-9) for T & D Losses in this period.
d. An actual quantity of 470,677 megawatt-hours for T & D Losses was recorded for this period. Please explain the variance shown between the recorded quantity and the estimated quantity of megawatt-hours for T & D Losses in this period.
e. Schedule A-1, Line 21, reports that the Adjusted Total Fuel and Net Power Transactions was over 7 percent higher than estimated amounts for dollars, and less than 1 percent lower than estimates for megawatt-hours. Please explain why T & D Losses (shown on Line 24) are higher by a larger percentage for dollars and megawatt-hours, than the entries for Line 21.

RESPONSE:
As noted on Schedule A-1, the amounts reflected on the A-1 Schedule associated with T&D losses are provided for informational purposes only and do not impact the calculation of the true-up amount. Actual and estimated MWh T&D losses are calculated as follows: adjusted total fuel and net power transactions (Net Energy for Load) minus company use, minus net unbilled sales, minus system sales (see response to subpart c.).

a.

- Actual $12,749,214 (Line 24, Column 3) = 2.7087 cents/kWh (Line 21, Column 11) *10 * 470,677 MWh (Line 24, Column 7)
- Estimated $11,318,946 (Line 24, Column 4) = 2.5002 cents/kWh (Line 21, Column 12) *10*452,717 MWh (Line 24, Column 8)
- Difference $1,430,268 (Line 24, Column 5) = Actual dollars $12,749,214 - Estimated dollars $11,318,946

b. The $1,430,268 variance in the actual dollar value for T&D losses is primarily attributable to higher than projected adjusted total fuel costs for net power transactions (Line 21, Column 13) and higher than projected T&D MWh losses (Line 24, Column 9).

c.

- Actual 470,677 MWh (Line 24, Column 7) = 8,667,019 MWh (Line 21) - (309,451) MWh (Line 23) – 9,352 MWh (Line 25) – (8,496,441,467 kWh/1000) (Line 26)
- Estimated 452,717 MWh (Line 24, Column 8) = 8,725,945 MWh (Line 21) - (249,073) MWh (Line 23) – 9,615 MWh (Line 25) – (8,512,686,092 kWh/1000) (Line 26)
- Difference 17,959 MWh (Line 24, Column 9) = 470,677 MWh (Line 24, Column 7) – 452,717 MWh (Line 24, Column 8)

d. The actual loss factor as a percentage of sales will vary from estimates due to a variety system conditions. A few of the system conditions that can impact loss factors include system peak load levels, system power factor, and availability of generation in relation to load.

e. The actual MWh of T&D losses was 4% higher than projected even though the actual MWh of adjusted total fuel and net power transactions (NEL) was slightly lower than projected. The higher MWh losses compounded with the 7.6% higher than projected dollar amount for adjusted total fuel and net power transactions resulted in a higher percentage variance on the T&D losses amount than the adjusted total fuel and net power transactions variance. As explained above, the calculation of T&D losses MWh and dollar amount is for informational purposes and does not impact the calculation of the true-up amount.

DECLARATION

I sponsored the answers to Interrogatory Nos. 9 through 16 from **STAFF'S SECOND SET OF INTERROGATORIES (NOS. 9-17)** to Florida Power & Light Company in Docket No. 20190001-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: 3/26/19

DECLARATION

I sponsored the answer to Interrogatory No. 17 from **STAFF'S SECOND SET OF INTERROGATORIES (NOS. 9-17)** to Florida Power & Light Company in Docket No. 20190001-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.

Renae B. Deaton

Date: 26 March 2019

85

FPL's Response to Staff's Third Set of Interrogatories, Nos. 18-23, and 24 (amended)

Additional files contained on Staff Hearing Exhibits CD/USB for No. 19

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 85
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: William F. Brannen (18-19, 21-24) Juan E. Enjamio (20)

QUESTION:
For the purpose of questions 18-20 and sub-parts, please refer to FPL's Petition for Approval of Solar Base Rate Adjustment to be effective 2020, as filed on March 1, 2019 (2020 SoBRA Projects).

Page 4, Paragraph 7, indicates that the designs "are not yet final." Please answer the following:

a. Will the "preliminary design" and "final design" considerations be site-specific, or programmatic (i.e., impacting all four of the 2020 SoBRA Projects)? Please explain your response.

b. Please indicate (or estimate) when designs should be finalized.

c. Using the terms "preliminary designs" and "final designs," please describe each change that is being considered. Include in your response the estimated amount by which "final design" costs will rise/fall compared to the costs based on "preliminary designs."

RESPONSE:

a. Both the "preliminary design" and "final design" considerations referenced in FPL's Petition and the testimony of witness Brannen are site-specific, not programmatic. Examples of changes that may occur at each site between the issuance of preliminary and final design documents include refinement of site layout as more detailed survey and geotechnical information becomes available, direct current (DC) and alternate current (AC) cable sizing adjustments to optimize performance, and minor changes to incorporate updated information received from suppliers regarding equipment performance or sizing information. These changes are not expected to increase the estimated cost of the project.

b. FPL expects that the designs will be finalized by June 1, 2019.

c. Please see FPL's response to Interrogatory No. 18(a), above.

QUESTION:
For the purpose of questions 18-20 and sub-parts, please refer to FPL's Petition for Approval of Solar Base Rate Adjustment to be effective 2020, as filed on March 1, 2019 (2020 SoBRA Projects).

Page 5, Paragraph 12, indicates that the preliminary estimates reflect the 2020 SoBRA Projects will cost $410.7 million, or $1,378 per kilowatt alternating current. Please provide worksheets and/or schedules with formulas intact to demonstrate how the $410.7 million estimated amount was calculated.

RESPONSE:
See Attachment I to this Interrogatory response.

QUESTION:
For the purpose of questions 18-20 and sub-parts, please refer to FPL's Petition for Approval of Solar Base Rate Adjustment to be effective 2020, as filed on March 1, 2019 (2020 SoBRA Projects).

Page 5, Footnote 1 of Paragraph 15, refers to a shared solar program. What portion of the output from the 2020 SoBRA Projects, if any, will be dedicated to serving the shared solar project?

RESPONSE:
None of the output of the 2020 SoBRA Project will be dedicated to serving the FPL SolarTogether community solar program.

QUESTION:
For the purpose of questions 21-24 and sub-parts, please refer to Exhibit WFB-3, attached to the Prepared Direct Testimony of William F. Brannen, on behalf of Florida Power & Light Company, as filed on March 1, 2019.

Please answer the following questions regarding the Hibiscus Solar Energy Center property:

a. What is the total acreage of the Hibiscus Solar Energy Center property?

b. Of the total acreage identified in the response to Interrogatory Number 21(A), how many acres are required (or planned) for this solar installation?

c. Of the remaining acres, those not required (or planned) for this solar installation, how many acres would be suitable for future solar installations, or for other utility purposes?

d. Of the remaining acres, those not required (or planned) for this solar installation, how many acres are not suitable for future solar installations, or for other utility purposes?

e. What was the purchase price, and how long has FPL owned the Hibiscus Solar Energy Center property?

RESPONSE:

a. The total size of the Hibiscus Solar Energy Center property is 401.65 acres.

b. The land required for this solar installation is 401.65 acres, which includes the solar array, the substation and transmission facilities, construction laydown areas, and other areas subject to permit conditions (such as land containing restricted waters, wetlands, as well as setbacks and landscape buffers). 100% of the land available at the site is required for this solar installation.

c. As noted in the response to Interrogatory No. 21(b) above, 100% of the land available at the site is required for this solar installation. Therefore, there is no land available for future solar installations or for other utility purposes.

d. As noted in the response to Interrogatory No. 21(b) above, 100% of the land available at the site is required for this solar installation. Therefore, there are no "remaining acres."

e. The Hibiscus Solar Energy Center property was acquired in June 2018 for a purchase price of $10.0 million.

QUESTION:
For the purpose of questions 21-24 and sub-parts, please refer to Exhibit WFB-3, attached to the Prepared Direct Testimony of William F. Brannen, on behalf of Florida Power & Light Company, as filed on March 1, 2019.

Please answer the following questions regarding the Okeechobee Solar Energy Center property:

a. What is the total acreage of the Solar Energy Center portion of the Okeechobee property?

b. Of the total acreage identified in the response to Interrogatory Number 22(A), how many acres are required (or planned) for this solar installation?

c. Of the remaining acres, those not required (or planned) for this solar installation, how many acres would be suitable for future solar installations, or for other utility purposes?

d. Of the remaining acres, those not required (or planned) for this solar installation, how many acres are not suitable for future solar installations, or for other utility purposes?

e. What was the purchase price, and how long has FPL owned the Solar Energy Center portion of the Okeechobee property?

RESPONSE:

a. The total size of the Okeechobee Solar Energy Center property is 471.26 acres.

b. This solar installation is being constructed on land where the Okeechobee Clean Energy Center (OCEC) is sited. The land required for this solar installation is 432.99 acres, which includes the solar array as well as the substation and transmission facilities.

c. None of the 38.27 remaining acres are suitable for future solar installation or other utility purposes. This is due to the fact that 23.74 acres are comprised of waters and wetlands, 2.13 acres are occupied by wells for OCEC, and 12.40 acres are comprised of small, isolated remote parcels that cannot be used for future solar installations or other utility purpose due to access limitations and attendant construction requirements.

d. As noted in the response to Interrogatory No. 22(c) above, none of the remaining 38.27 acres is suitable for future solar installations or other utility purposes.

e. This solar installation is being constructed on land originally purchased for OCEC. This entire acreage (2,842 acres) was acquired in June 2011 as a whole parcel. No value was assigned to the portion used for the Okeechobee Solar Energy Center, and no cost for this portion of the land will be included in FPL's SoBRA request.

QUESTION:
For the purpose of questions 21-24 and sub-parts, please refer to Exhibit WFB-3, attached to the Prepared Direct Testimony of William F. Brannen, on behalf of Florida Power & Light Company, as filed on March 1, 2019.

Please answer the following questions regarding the Southfork Solar Energy Center property:

a. What is the total acreage of the Southfork Solar Energy Center property?

b. Of the total acreage identified in the response to Interrogatory Number 23(A), how many acres are required (or planned) for this solar installation?

c. Of the remaining acres, those not required (or planned) for this solar installation, how many acres would be suitable for future solar installations, or for other utility purposes?

d. Of the remaining acres, those not required (or planned) for this solar installation, how many acres are not suitable for future solar installations, or for other utility purposes?

e. What was the purchase price, and how long has FPL owned the Southfork Solar Energy Center property?

RESPONSE:

a. The total size of the Southfork Solar Energy Center property is 548.30 acres.

b. The land required for this solar installation is 472.10 acres, which includes the solar array, the substation and transmission facilities, construction laydown areas, and other areas subject to permit conditions (such as roads, easements, setbacks and landscape buffers).

c. None of the 76.20 remaining acres are suitable for future solar installation or other utility purposes. This is due to the fact that 75.03 acres are comprised of flood zones, waters, and wetlands, and the remaining 1.17 acres is a small, isolated remote parcel that cannot be used for future solar installations or other utility purpose due to access limitations and attendant construction requirements.

d. As noted in the response to Interrogatory No. 21(c) above, none of the remaining 76.20 acres are suitable for future solar installations or other utility purposes

e. The Southfork Solar Energy Center property was acquired in February 2019 for a purchase price of $3.6 million.

QUESTION:
For the purpose of questions 21-24 and sub-parts, please refer to Exhibit WFB-3, attached to the Prepared Direct Testimony of William F. Brannen, on behalf of Florida Power & Light Company, as filed on March 1, 2019.

Please answer the following questions regarding the Echo River Solar Energy Center property:

a. What is the total acreage of the Echo River Solar Energy Center property?

b. Of the total acreage identified in the response to Interrogatory Number 24(A), how many acres are required (or planned) for this solar installation?

c. Of the remaining acres, those not required (or planned) for this solar installation, how many acres would be suitable for future solar installations, or for other utility purposes?

d. Of the remaining acres, those not required (or planned) for this solar installation, how many acres are not suitable for future solar installations, or for other utility purposes?

e. What was the purchase price, and how long has FPL owned the Echo River Solar Energy Center property?

RESPONSE:

a. The total size of the Echo River Solar Energy Center property is 802.29 acres.

b. The land required for this solar installation is 556.85 acres, which includes the solar array, the substation and transmission facilities, construction laydown areas, and other areas subject to permit conditions or restrictions (such as restricted land containing archeological sites as well as roads and easements).

c. Of the remaining acres, 203.74 are not suitable for future solar installation or other utility purposes. This is due to the fact that 185.18 acres are comprised of flood zones, waters and wetlands as well as major sinks, while the remaining 18.56 acres are comprised of several small, isolated remote parcels that cannot be used for future solar installations or other utility purposes due to access limitations and attendant construction requirements.

d. The remaining 41.70 acres may be suitable for future solar installations or other utility purposes, subject to environmental and other permitting constraints.

e. The Echo River Solar Energy Center property was acquired in March 2017 for $4.8 million.

DECLARATION

I sponsored the answers to Interrogatory Nos. 18 through 19 and Nos. 21 through 24 from **STAFF'S THIRD SET OF INTERROGATORIES (NOS. 18-24)** to Florida Power & Light Company in Docket No. 20190001-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.

William F. Brannen

Date: 4/11/2019

DECLARATION

I sponsored the answer to Interrogatory No. 20 from **STAFF'S THIRD SET OF INTERROGATORIES (NOS. 18-24)** to Florida Power & Light Company in Docket No. 20190001-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.

Juan E. Enjamio

Date: 4/10/2019

DECLARATION

I sponsored the answer to Interrogatory No. 24 amended from **STAFF'S THIRD SET OF INTERROGATORIES (NOS. 18-24)** to Florida Power & Light Company in Docket No. 20190001-EI. The response is 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.

William F. Brannen

Date: October 21, 2019

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FPL's Response to Staff's Fourth Set of Interrogatories, Nos. 25 (amended) and 26-40

Additional files contained on Staff Hearing Exhibits CD/USB for Nos. 21, 36, 37, 38, and 39.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 86
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: William F. Brannen (25-26, 38) Juan E. Enjamio (27-37, 39-40)

QUESTION:
Land
For each 2020 SoBRA project please identify the amount of acreage considered: state or federally jurisdictional wetlands, drainage improvements, county or improvement setback areas or shared easements.

RESPONSE:
FPL's responses to Staff's Third Set of Interrogatories, Nos. 21, 22, 23, and 24 provide an overall description of each site with regard to the acreage utilized for the solar installation as well as the acreage that is and is not suitable for future solar installations or utility purposes. The table below provides further detail related to the acreage use for each of the categories depicted in Exhibit WBF-3 attached to the Prepared Direct Testimony of William F. Brannen, on behalf of Florida Power & Light Company, as filed on March 1, 2019:

Land Category	Acreage
Hibiscus Solar Energy Center	
Solar Array	364.90
Substation/Transmission	12.7
Construction Laydown	7.30
Waters and Wetlands	16.75
Okeechobee Solar Energy Center	
Solar Array	432.38
Substation/Transmission	0.61
Waters and Wetlands	23.74
Okeechobee Clean Energy Center Use	2.13
Remote, Isolated Parcels	12.4
Southfork Solar Energy Center	
Solar Array	458.28
Substation/Transmission	2.81
Construction Laydown	4.19
Waters and Wetlands	45.17
Flood Zone	29.86
Roads/Easements	6.82
Remote, Isolated Parcels	1.17
Echo River Solar Energy Center	
Solar Array	488.20
Substation/Transmission	17.86
Construction Laydown	16.69
Waters and Wetlands	167.00
Flood Zone	8.42

Major Sink	9.76
Suitable for future use or leasing to a third party	41.70
Archeological Site	22.80
Roads/Easements	11.30
Remote, Isolated Parcels	18.56

With regard to the categories requested by Interrogatory No. 25, specifically, state or federally jurisdictional wetlands, drainage improvements, county or improvement setback areas or shared easements, FPL has assumed these categories within the more detailed classifications outlined in the table above and in the responses to Staff's Third Set of Interrogatories, Nos. 21, 22, 23, and 24 consistent with the explanation below:

- State or federally jurisdictional wetlands are included within the "Waters or Wetlands" classification for each of the four 2020 SoBRA sites
- Drainage improvements are included within the "Solar Array" classification or within the "Waters and Wetlands" classification for each of the four 2020 SoBRA sites
- County or improvement setback areas are included within "Solar Array" classification for each of the four 2020 SoBRA sites.
- Shared easements are captured as "Roads/Easements" for the Southfork and Echo River sites. At Hibiscus, the "Waters and Wetlands" category captures certain shared easements along canals that are held by the local improvement district.

QUESTION:
Land
Please detail how existing sites were chosen as suitable for solar development.

RESPONSE:
Please see witness Brannen's testimony (starting on Page 9, Line 14 through Page 19, Line 3), which provides an explanation of how FPL acquired the property and optimized the land for each of the energy centers. The following provides further detail about FPL's site selection methodology:

- In order to identify a solar site for potential acquisition, FPL conducts a search using a variety of screening criteria to find sites with specific locational and environmental attributes, including:
  - Non-residential, accessible land, preferably disturbed land
  - Land parcels with one owner (if possible) to reduce the administrative burden of processing transactions
  - Proximity to existing FPL transmission lines operating at voltages between 115kV to 230kV
  - Land with minimal wetlands, endangered species, cultural resources, or other potential environmental constraints
  - Geographic diversity within the FPL service territory

- When FPL identifies a suitable site and is successful in securing a commercial agreement for sale and/or access to the site, FPL embarks on an extensive due diligence process involving a variety of subject matter experts including (but not limited to) representatives from environmental services, engineering and construction, real estate, legal, and transmission. This team evaluates each site more rigorously in order to identify fatal flaws, tentative development timelines and costs. Specific steps in the due diligence process include:
  - Completion of property title research and land surveys
  - Environmental site assessments
  - Environmental reports on wetlands, species, cultural resources and applicable mitigation costs
  - Engineering field reconnaissance
  - Conceptual site layout
  - Geotechnical analysis
  - Interconnection feasibility (including evaluation of right-of-way requirements)
  - Capital and operating cost estimates
  - Local land development regulation review / permit feasibility analysis

Each of the sites proposed for the 2020 Project passed favorably through the land screening process described above. Additionally, among suitable sites, the four sites selected for the 2020 Project were the most advanced in development and permitting, which reduced schedule and execution risks.

QUESTION:
Resource Planning

Please refer to FPL Exhibit JE-3 and Schedule 8 in FPL's 2019 Ten Year Site Plan.
a. Please explain which resource plan is FPL's most up-to-date resource plan. If the Ten Year Site Plan is the most recent, please provide revised Exhibits JE-1 through JE-4.

RESPONSE:
The 2019 Ten Year Site Plan (TYSP), shown in Schedule 8, is the starting point in the development of the resource plans used in analyzing the economics of FPL's 2020 Project. The TYSP is the result of FPL's integrated resource planning studies conducted in late 2018 and early 2019 and is FPL's current view of its long-term resource needs.

It is FPL's practice when evaluating the economics of solar projects to compare the specific solar project against a "base-case" resource plan, which includes only those solar projects in-service or already approved and under construction. FPL has followed this practice in its economic analysis for all of its existing solar projects, including the three sites constructed in 2016, as well as the 2017, 2018 and 2019 solar projects constructed pursuant to the Solar Base Rate Adjustment ("SoBRA") provision in FPL's rate settlement agreement.

In 2019, FPL is requesting the Commission to approve (i) the FPL SolarTogether Program which consists of 1,490 MW of solar generation and (ii) the 2020 Project pursuant to the SoBRA provision. Because each of these is subject to separate approval by the Commission, FPL completed separate economic analyses.

FPL first evaluated SolarTogether. This program adds 1,490 MW of solar nameplate capacity to be placed in-service in 2020 and 2021. For the economic analysis of the SolarTogether project FPL developed a base case resource plan, which did not include any future solar generation beyond the 1,490 MW. The SolarTogether evaluation started with the TYSP, but then removed future solar projects as capacity options and developed a new optimized plan. FPL then created another resource plan, which did include the 1,490 MW of SolarTogether capacity, but no other future solar. The economics of the SolarTogether project are based on the difference in CPVRR of these two plans.

For the 2020 Project, which is the subject of this filing, FPL assumed that the 1,490 MW of SolarTogether generation was included in the base case used for this project. In other words, the 2020 SoBRA project was evaluated against the resource plan that includes the SolarTogether Program, but no additional new solar generation. FPL then created a case with the 2020 Project. Again, the economics of the 2020 Project are based on the difference in CPVRR of these two cases. While the TYSP resource plan is FPL's current long-term view of future resource needs, FPL believes that the two resource plans shown in FPL's Exhibit JE-3 are the proper resource plans to be used in evaluating the economics of the 2020 Project.

QUESTION:
Resource Planning
Please refer to FPL Exhibit JE-3 and Schedule 8 in FPL's 2019 Ten Year Site Plan.
a. Please explain the discrepancy between the presence of the 1,043 MW Solar Together in 2021 on JE-3 and its absence in Schedule 8.

b. Please explain the discrepancy between the resource plans in regards to the 2023 through 2028 Solar PV Units.

c. Please explain the discrepancy between the resource plans in regards to the in-service date of the 1,866 MW CC Unit.

d. Please explain why there are no solar units planned for 2026 in FPL's Ten Year Site Plan.

RESPONSE:
(a) The FPL 2019 Ten Year Site Plan ("TYSP") only included 447 MW nameplate solar capacity (or 248 MW of firm solar capacity) in the year 2026. At the time the TYSP resource plan was developed, the SolarTogether Program was not finalized and was not included in the TYSP plan. In effect, the SolarTogether Program will result in the acceleration of solar projects shown in later years in the TYSP to earlier years.

(b) Please see response to Interrogatory 27

(c) The resource plans used to evaluate this Project did not include new solar capacity after the solar generation added in this Project and the SolarTogether Program (please see response to Interrogatory 27). As a result, the resource plans used in evaluating this Project have less firm solar capacity being added and the 1,866 MW CC unit shown coming in-service in 2026 in FPL's 2019 TYSP is needed two years earlier.

(d) Additional solar units that could be placed in-service in 2026 were available as future generation options in FPL's 2019 Integrated Resource Analysis process. This process used the Electric Generation Expansion Analysis System (EGEAS) optimization model to develop FPL's resource plan. The model considers a number of factors when selecting resources for each year. These factors include, but are not necessarily limited to, the following: annual peak load growth, amount of available resource option per year, firm capacity of each resource option, and system economics. Based on these considerations, the EGEAS model did not select solar projects in 2026, but selected a 2026 CC unit as part of FPL's optimized resource plan, as shown in FPL's 2019 Ten Year Site Plan.

QUESTION:
Resource Planning
Please refer to FPL's 2019 Ten Year Site Plan, Table ES-1 and Witness Enjamio Testimony page 6, line 10. Please explain the discrepancy between the summer firm capacity of 165 MWac for 2020 SoBRA units and the 182 MWac summer firm capacity for 2020 SoBRA units.

RESPONSE:
In FPL's 2019 Ten Year Site Plan (Site Plan), Table ES-1, FPL shows ten solar sites coming into-service in 2020, four of which were the 2020 SoBRA Project sites. FPL used a firm capacity value of 55.4% for all ten solar sites, resulting in total firm capacity value for all ten sites of 413 MW, 165 MW which were assigned to the 2020 SoBRA Project sites.

In its 2020 SoBRA Project filing, FPL used the expected firm capacity value for the four specific sites, based on their actual designs. The firm capacity value for the four SoBRA Project sites is 61.1%. As a result, the firm capacity value of the 2020 SoBRA Project sites is 182 MW.

QUESTION:
Resource Planning
Please refer to the 2020 100 MW Battery in FPL Exhibit JE-3.
a. Please describe any studies conducted in regards to the 100 MW Battery.

b. Please refer to JE-4 and if applicable, Revised Exhibit JE-4. Please list the columns that have cost and benefits associated with the 100 MW Battery.

c. Please refer to JE-4 and if applicable, Revised Exhibit JE-4. Please detail the amounts associated with the 100 MW Battery for each column.

d. Please provide the economic assumptions FPL used in the resource planning process.

RESPONSE:
a. FPL has not conducted any studies in regards to the 100 MW battery. The 100 MW battery was one of the future resource options available in the resource planning optimization process.
b. The columns that have costs and benefits (avoided costs) associated with the 100 MW Battery are: Generation Capital, Fixed O&M, and Avoided System Costs (fuel, start-up and VOM, and emission costs).
c. The values (CPVRR) used for Generation Capital and Fixed O&M for the 100 MW battery are shown on the table below. The variable system costs impact of the battery are the cost of fuel required to charge the battery, including charging losses, offset by the reduction in the fuel and O&M costs of generation displaced by the battery. These variable system costs of the battery cannot be isolated from the overall variable system costs for the two resource plans ("No 2020 Project Plan" and "2020 Project Plan").

100 MW Battery	
Generation Capital (Millions)	Fixed O&M (Millions)
($49)	($12)

d. FPL assumes that this question is asking about the assumptions associated with the 100 MW battery. These assumptions are shown below:

Book Life (Years):	40
Total Installed Cost (2020 $/kW):	538.37
Direct Construction Cost (2020 $/kW):	530.59
AFUDC Amount (2020 $/kW):	7.8
Fixed O&M ($/kW-Yr.):	10.82
Long Term Capital Replenishment ($/kW)	288.48
Variable O&M (2020 $/MWH):	---

QUESTION:
Economics
Using FPL's most up-to-date resource plan, please provide the annual and cumulative values over the life of the project (in nominal and net present value) for each of the following categories: Equipment and Installation, Incremental Fixed O&M, Fuel Savings, Emissions Savings separated by type (CO2,etc.), Avoided Replacement Costs, Avoided Capacity Purchases, Avoided Fixed O&M, Avoided Variable O&M. Please provide this response in electronic (Excel) format.
a. Please explain in detail the assumptions, facts, and figures used to determine the value of each of the components evaluated in this analysis.

b. Please explain whether FPL's generation only reserve margin was a factor in requiring avoided generation purchases or avoided replacement costs. If so, please provide a sensitivity of the analysis based upon Loss-of-Load-Probability and a 20 percent reserve margin criteria only and provide a revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.

c. Please explain whether FPL's emissions savings include CO2 or CO2 equivalent emissions. If so, please provide a sensitivity of the analysis without these costs and provide the revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.

d. Please explain whether FPL reviewed the cost-effectiveness of the generation upgrades using fuel price sensitivities. As part of this response, please provide a sensitivity of the fuel savings based upon a low fuel price forecast and a high fuel price forecast, with revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.

RESPONSE:
See Attachment 1 to this Interrogatory response for the annual and cumulative values over the life of the 2020 SoBRA Project for each category requested.
(a) Please see explanation of each component evaluated in this analysis below:

Solar Revenue Requirements:

Generation Capital – This category includes the equipment and installation associated with the deployment of the 2020 Project (includes capital cost, land cost, and transmission interconnection cost). These capital cost assumptions can be found in FPL Witness Brannen's testimony and FPL's answer to Staff's Fourth Set of Interrogatories, No. 38.

Incremental Fixed O&M – This category includes the operation and maintenance (O&M) costs of the 2020 Project. These values can be found in Attachment 1 to this response.

Non-Solar (Avoided) Generation Costs:

Avoided Generation Capital – This category reflects the reduction in the capital costs of future FPL capacity avoided by the deployment of the 2020 Project. These reductions are based on the difference in Resource Plans seen in the table provided below in response to part (b) of this interrogatory. The annual avoided generation capital costs can be found in Attachment 1 to this response.

Avoided Fixed O&M – This category reflects the reduction in the fixed O&M costs of future FPL capacity avoided by the deployment of the 2020 Project. These reductions are based on the difference in Resource Plans seen in the table provided below in response to part (b) of this interrogatory. The annual Fixed O&M can be found in Attachment 1 to this response.

Avoided Transmission Interconnection – This category reflects the reduction in the transmission interconnection of future capacity avoided by the deployment of the 2020 Project. These reductions are based on the difference in Resource Plans seen in the table provided below in response to part (b) of this interrogatory. The annual avoided capital replacement costs can be found in Attachment 1 to this response.

Avoided Capital Replacement – This category reflects the reduction in capital replacement (ongoing costs of parts) due to avoided future FPL capacity from deployment of the 2020 Project. These reductions are based on the difference in Resource Plans seen in the table provided below in response to part (b) of this interrogatory. The annual capital replacement costs can be found in Attachment 1 to this response.

Incremental Gas Transport – This category reflects the reduction in gas transportation costs of future FPL capacity avoided by the deployment of the 2020 Project. This reduction is based on the comparison of the gas transportation costs of both resource plans. The annual incremental gas transport costs can be found in Attachment 1 to this response.

Short-Term Purchases – This category reflects the avoided capacity payments that reflect reductions in short-term (one year) power purchase agreements avoided due to the deployment of the 2020 Project. FPL purchases power available on the market in order to meet the capacity need for the specific year.

Avoided System Cost:

Fuel Savings – This category shows system fuel savings resulting from the deployment of the 2020 Project. These fuel savings are based and derived from FPL's fuel price forecast assumptions. Please see Exhibit JE-2 to Mr. Enjamio's testimony in this docket for this forecast. These annual fuel savings can be found in Attachment 1 to this response.

Avoided Startup and Variable O&M – This category reflects the reduction in the startup costs and variable O&M costs of FPL's conventional units from reduced operation resulting from the deployment of the 2020 Project. These annual avoided startup and variable O&M can be found in Attachment 1 to this response.

Emissions Savings – This category reflects the reduction in FPL system emissions due to the deployment of the 2020 Project. The CO2 component contributes approximately 99% of these savings. The CO2 cost assumptions are obtained from ICF International.

(b) FPL interprets the phrase "…requiring avoided generation purchases or avoided replacement costs" in this interrogatory to mean short-term or long-term capacity additions.

FPL uses three criteria to evaluate the reliability and adequacy of its generation system: 20% total reserve margin (RM), 10% generation-only reserve margin (GRM), and loss of load probability (LOLP), 1 day per year. FPL's Resource Plan is based on the concurrent application of all three criteria. If FPL ignored its GRM criterion and developed a resource plan based solely on the total RM and LOLP criteria, then the total RM criterion would dictate the timing of capacity additions.

As requested, FPL has developed alternate "No 2020 Project Plan" and "2020 Project Plan" cases ignoring the use of the GRM criteria. The timing of resource additions in these alternate cases is driven solely by the 20% reserve margin criterion. These alternate resource plans are presented in the table below. As shown in this table, the resulting plans showed no change to the ones FPL presented in its filing, that showed a savings of $26 million CPVRR.

Year	No 2020 Project Plan	2020 Project Plan
2020	447 MW Solar Together; 100 MW Battery	2020 Project (298 MW); 447 MW FPL SolarTogether
2021	1,043 MW FPL SolarTogether	1,043 MW FPL SolarTogether
2022	Dania Beach Energy Center, 469 MW Manatee battery, Manatee 1-2 retire,	Dania Beach Energy Center, 469 MW Manatee battery, Manatee 1-2 retire,
2023	Greenfield 469 MW CT Unit	Greenfield 469 MW CT Unit
2024	Greenfield 1,886 MW CC Unit	Greenfield 1,886 MW CC Unit
2025		
2026		
2027		
2028	Greenfield 1,886 MW CC Unit	Greenfield 1,886 MW CC Unit
2029		
2030	Greenfield 704 MW CT Unit	Greenfield 704 MW CT Unit
2031	Equalizing 266 MW CC Unit	Equalizing 180 MW CC Unit

(c) Yes, FPL's emissions savings for these projects did include costs for CO2 emissions. This is consistent with FPL's current resource planning practices. Please refer to the response to Part d. below, which shows various sensitivities of fuel and CO2 costs, including no CO2 emissions costs.

(d) FPL reviewed the cost-effectiveness of the generation upgrades using various fuel and CO2 compliance costs sensitivities (see description of these sensitivities below). Attachment 2 shows the results of these sensitivities. As the attachment shows, the 2020 Project is cost-effective in 7 out of the 9 fuel and CO2 compliance cost sensitivities.

FPL used two fuel sensitivities in addition to the base case. These sensitivities (low and high) varied the price of natural gas, while keeping all other fuel prices (i.e., oil and coal) the same in all three fuel price scenarios.

FPL used two CO2 compliance costs sensitivities in addition to the base case. The Low CO2 assumed the low environmental compliance costs (which has a $0/ton costs annually), Mid CO2 assumed the "most likely" environmental compliance costs, and High CO2 assumed the high environmental compliance costs. All CO2 cost projections are provided by and based on ICF's forecasts. Adding the 2020 Project to FPL's system also provides the benefit of diversifying FPL's fuel mix and reducing air emissions.

QUESTION:
Reserve Margin
Please detail the Reserve Margin percentage that the "No 2020 Project Plan" and "2020 Project Plan" were evaluated at, using FPL's most up-to-date resource plan.

RESPONSE:
The following table shows both the 20% Reserve Margin and the 10% Generation-Only Reserve Margin for both resource plans.

	No 2020 Project Plan		2020 Project Plan	
Year	Total Reserve Margin After Maintenance % of Peak	Generation Only Reserve Margin After Maintenance % of Peak	Total Reserve Margin After Maintenance % of Peak	Generation Only Reserve Margin After Maintenance % of Peak
2020	20.3%	11.3%	20.7%	11.7%
2021	21.4%	12.3%	21.8%	12.7%
2022	20.6%	11.6%	21.0%	12.0%
2023	20.8%	12.0%	21.2%	12.3%
2024	26.7%	17.5%	27.0%	17.9%
2025	24.8%	15.9%	25.1%	16.3%
2026	22.5%	14.0%	22.9%	14.3%
2027	20.1%	11.9%	20.4%	12.2%
2028	25.1%	16.7%	25.5%	17.0%
2029	22.0%	14.0%	22.4%	14.3%
2030	21.5%	13.7%	21.9%	14.0%
2031	20.0%	12.4%	20.0%	12.4%

QUESTION:
Bill Impact
Please provide an estimate of the monthly residential bill impact ($/1000-kwh-mo) for the period 2020-2050 with the addition of all 2020 SoBRA units.

RESPONSE:
FPL does not have a long-term projection of bill impact by rate class. The following table shows a projected system bill impact, not allocated by rate class, through the year 2050. FPL will calculate and file short-term bill impacts by class at the time of its projection filing due September 3, 2019.

Year	Annual System Bill Impact $/1000 kWh
2020	0.210
2021	0.224
2022	0.205
2023	0.177
2024	0.157
2025	0.139
2026	(0.004)
2027	(0.020)
2028	(0.006)
2029	(0.018)
2030	(0.021)
2031	(0.097)
2032	(0.124)
2033	(0.139)
2034	(0.148)
2035	(0.168)
2036	(0.173)
2037	(0.193)
2038	(0.195)
2039	(0.196)
2040	(0.214)
2041	(0.259)
2042	(0.275)
2043	(0.293)
2044	(0.306)
2045	(0.302)
2046	(0.324)
2047	(0.312)
2048	(0.344)
2049	(0.364)
2050	(0.400)

QUESTION:
Cost Effectiveness
Please refer to EXH JE-4 and Revised EXH JE-4.
a. For Solar Revenue Requirement, please explain what costs are included in each category (Generation Capital, Fixed O&M, etc....) and how these costs were calculated. Particularly, please explain if Transmission Capital is included in the Generation Capital category.

b. For the Solar Revenue Requirements. Please explain if Transmission Capital is included in the Generation Capital Column. If so, please provide the amount that is in Generation Capital. If not, please provide a revised exhibit that includes Transmission Capital.

c. For Non-Solar Generation Costs, please explain what costs are included in each category (Generation Capital, Fixed O&M, etc....) and how these costs were calculated.
d. For Avoided System Costs, please explain what costs are included in each category (System Net Fuel, etc....) and how these costs were calculated.

RESPONSE:

a. Yes, Transmission Capital is included in the Generation Capital Category. Please see FPL's response to Staff's Fourth Set of Interrogatories Number 31a for an explanation of the costs that are included in each category that comprises the Solar Revenue Requirement.

b. Yes, Transmission Capital is included in the Generation Capital column. Please see Attachment 1 to this Interrogatory response for these values.

c. Please see FPL's response to Staff's Fourth Set of Interrogatories, Number 31a.

d. Please see FPL's response to Staff's Fourth Set of Interrogatories, Number 31a.

Solar Revenue Requirements	
Generation Capital (Millions)	Transmission Interconnection (Millions)
$363	**$39**

	Solar Revenue Requirements	
Year	Generation Capital (Millions)	Transmission Interconnection (Millions)
2019	$0.0	$0.0
2020	$31.9	$3.4
2021	$44.7	$4.7
2022	$41.6	$4.5
2023	$39.4	$4.4
2024	$37.4	$4.2
2025	$35.7	$4.1
2026	$34.5	$3.9
2027	$33.4	$3.8
2028	$32.4	$3.6
2029	$31.4	$3.5
2030	$30.4	$3.3
2031	$29.4	$3.2
2032	$28.4	$3.0
2033	$27.4	$2.9
2034	$26.3	$2.7
2035	$25.3	$2.6
2036	$24.3	$2.5
2037	$23.3	$2.4
2038	$24.3	$2.3
2039	$23.1	$2.2
2040	$21.9	$2.1
2041	$20.7	$2.0
2042	$19.6	$1.9
2043	$18.4	$1.8
2044	$17.2	$1.7
2045	$16.2	$1.6
2046	$15.2	$1.5
2047	$14.2	$1.4
2048	$13.3	$1.3
2049	$12.3	$1.2
2050	$6.3	$0.5
CPVRR =	**$363**	**$39**

QUESTION:
Resource Planning
Please refer to Witness Enjamio Testimony Page 3, Line 18. Please provide the first year net capacity factor and summer firm capacity value for each solar center.

RESPONSE:

Solar Center	**1st Year Net Capacity Factor (%)**	**Summer Firm Capacity Value (%)**
Hibiscus Facility	26.2%	57.5%
Okeechobee Facility	27.1%	53.8%
Southfork Facility	31.1%	64.5%
Echo River Facility	30.4%	68.6%
Average =	**28.7%**	**61.1%**

QUESTION:
Resource Planning

Please provide the expected annual outputs and capacity factors of each solar facility listed below for the period 2020-2050. Provide the response in tabular electronic form in Excel.
a. Hibiscus Facility
b. Okeechobee Facility
c. Southfork Facility
d. Echo River Facility

RESPONSE:
Please see Attachment 1.

QUESTION:
Economics
Please provide a comparison of the 2020 Solar Project Plan to customer owned residential rooftop installations with an equivalent installed capacity. Please assume residential customers install 5kW rooftop systems at each residence. Please include any assumptions and how these assumptions were made.

RESPONSE:
For the purpose of this comparison, FPL determined the number of distributed 5 kW systems that would provide the same firm capacity value as that provided by FPL's 2020 Project. To develop the capital cost and energy performance assumptions used in this analysis for the 5 kW systems, FPL started with actual roof-top solar data available from the first quarter of 2019, FPL also assumed that the 5 kW systems would have the same firm capacity value, O&M costs, and useful life as FPL's 2020 Project. FPL made these modifications to the assumptions even though it expects that 5 kW systems will have higher actual capital costs and lower energy output that the values used in this analysis, and also expects that they will have significantly higher O&M costs, lower firm capacity value, and lower useful life than universal solar systems. These assumptions are listed in Attachment I to this response.

Attachment 2 to this response shows the results of the requested economic comparison. The case based on the installation of 5 kW systems results in an increase in Cumulative Present Value of Revenue Requirements (CPVRR) of $619 million. This compares to a reduction of $26.1 million in CPVRR for FPL's 2020 Project.

QUESTION:
Installed Cost
For each of the 2020 solar projects, please complete the table below and explain all included components used towards the $1,750 kWac cost cap.

RESPONSE:
Please see FPL's response to Staff's 3rd Set of Interrogatories, No. 19 which provides a table showing the cost component for the 2020 Project and Attachment 1 to this response for the estimated cost for the components for each site that comprises the 2020 Project.

QUESTION:
For the 2020 planned solar generation please complete the table using FPL's most up-to-date resource plan and file it in electronic (excel) format.

RESPONSE:
Please see Attachment 1.

QUESTION:
Capacity Factor
For each in-service solar and/or PV project please fill out the following table.

RESPONSE:
Please see Attachment 1.

Project Name:	DeSoto Solar Facility	
In-service Date:	October 2009	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	21.7	26.8
2011	21.2	23.5
2012	21.0	23.7
2013	20.8	22.8
2014	20.7	23.2
2015	20.5	22.8
2016	20.3	22.2
2017	20.2	22.0
2018	20.0	21.4

Project Name:	Space Coast Solar Facility	
In-service Date:	April 2010	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	19.8	22.7
2011	19.6	21.4
2012	19.4	21.1
2013	19.3	20.7
2014	19.1	20.0
2015	19.0	20.2
2016	18.8	20.8
2017	18.7	20.0
2018	18.5	20.0

Project Name:	Martin Solar Facility	
In-service Date:	January 2012	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	23.6	13.5
2013	23.6	13.3
2014	23.6	17.3
2015	23.6	13.6
2016	23.6	11.4
2017	23.6	1.9
2018	23.6	7.8

Project Name:	Citrus Solar Facility	
In-service Date:	December 2016	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	26.1	25.3
2018	26.1	25.3

Project Name:	Babcock Solar Facility	
In-service Date:	December 2016	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	26.1	25.1
2018	26.1	25.3

Project Name:	Manatee Solar Facility	
In-service Date:	December 2016	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	26.1	25.9
2018	26.1	25.5

Project Name:	Coral Farms Solar Facility	
In-service Date:	January 2018	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	—	—
2018	26.8	23.5

Project Name:	Horizon Solar Facility	
In-service Date:	January 2018	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	—	—
2018	27.0	23.8

Project Name:	Wildflower Solar Facility	
In-service Date:	January 2018	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	—	—
2018	26.9	25.5

Project Name:	Indian River Solar Facility	
In-service Date:	January 2018	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	—	—
2018	26.2	24.9

Project Name:	Longerhead Solar Facility	
In-service Date:	March 2018	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	—	—
2018	26.5	24.0

Project Name:	Hammock Solar Facility	
In-service Date:	March 2018	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	—	—
2018	26.9	24.2

Project Name:	Blue Cypress Solar Facility	
In-service Date:	March 2018	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	—	—
2018	26.2	23.6

Project Name:	Barefoot Bay Solar Facility	
In-service Date:	March 2018	
Year	Projected Capacity Factor (%)	Actual Capacity Factor (%)
2009	—	—
2010	—	—
2011	—	—
2012	—	—
2013	—	—
2014	—	—
2015	—	—
2016	—	—
2017	—	—
2018	26.9	25.5

DECLARATION

I sponsored the answers to Interrogatory Nos. 25 through 26 and Nos. 38 from **STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 25-40)** to Florida Power & Light Company in Docket No. 20190001-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.

William F. Brannen

Date: 5/22/2019

DECLARATION

I sponsored the answer to Interrogatory No. 27 through 37 and 39 through 40 from **STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 25-40)** to Florida Power & Light Company in Docket No. 20190001-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.

Juan E. Enjamio

Date: 5/23/2019

DECLARATION

I sponsored the answers to Interrogatory No. 25 amended from **STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 25-40)** to Florida Power & Light Company in Docket No. 20190001-EI. The response is 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.

William F. Brannen

Date: October 21, 2019

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FPL's Response to Staff's Sixth Set of Interrogatories, Nos. 43-54

Additional files contained on Staff Hearing Exhibits CD/USB for Nos. 45, 47, 48, 49, 50.

CONFIDENTIAL DN. 08889-2019

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 87
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Juan E. Enjamio (43-51, 52, 54)William F. Brannen (53)

QUESTION:
Please refer to FPL witness Enjamio testimony, page 5, lines 6 - 11. Please provide a timeline of the planning process that occurred for the 2020 SoBra project. This timeline should include construction dates, permitting dates, internal planning dates, etc.

RESPONSE:
See table below:

2020 SoBRA Timeline

Start of Site Development Activities	September	2017
Start of Permitting Activities	December	2017
Economic Analysis Complete	February	2019
Start of Equipment/EPC Contract Activities	3rd Quarter	2018
2020 SoBRA filing	March 1	2019
End of Permitting Activities **	1st Quarter	2019
End of equipment/EPC Contract Activities	March	2019
Start Commercial Operations	April	2020

QUESTION:
Please refer to FPL witness Enjamio testimony, page 5, lines 6 - 11. Please provide a timeline of the planning process that occurred for the SolarTogether project. This timeline should include construction dates, permitting dates, internal planning dates, etc.

RESPONSE:
Please see table below.

FPL Solar Together Timeline

Conceptual program design, first market research	1st Quarter	2017
First program "concept" discussions with C&I customers	April	2017
Start of Site Development Activities *	September	2017
Start of Permitting Activities	3rd quarter	2017
Preliminary financial analysis	September	2018
Updated financial analysis	December	2018
Start of Equipment/EPC Contract Activities	3rd Quarter	2018
Updated Program Design	February	2019
FPL SolarTogether Petition filing	March 13	2019
End of Permitting Activities **	4th quarter	2019
Start Commercial Operations - Phase I	March	2020
End of equipment/EPC Contract Activities	April	2021
Start Commercial Operations - Phase II	February	2021
Start Commercial Operations - Phase III	April	2021

* *One of the sites used for SolarTogether was originally developed as a potential site for the 2019 SoBRA project, but not used in that project. As a result, its development started earlier than the other SolarTogether sites.*

QUESTION:
Please refer to FPL witness Enjamio testimony, page 6, lines 7 - 13. Please explain how FPL determined the total firm capacity value for both summer and winter peak. As a part of this response, please provide the annual projected capacity factor for the life of each of the 2020 centers.

RESPONSE:
FPL determines the summer-firm capacity value of each solar center based on its output at the time of summer peak. An energy profile is developed for each project. This energy profile is in the 12 x 24 format, *i.e.*, it consists of a 24-hour profile of projected energy generation for each month. The monthly profile represents the average of all days in the given month. From this profile, FPL identifies the generation produced by the solar center at the summer peak hour, which is projected to be in August, starting at 4 pm. For the SoBRA Project, the average summer-firm capacity value is 61% of the nameplate value.

The same process is repeated for identifying the winter firm-capacity value. The winter peak hour is projected to be in January, starting 7 am. At this hour, the solar generation, as shown in the January energy profile is negligible. FPL therefore concludes that the solar energy centers have no winter-firm capacity value.

FPL undertakes a second review of the summer firm-capacity value of solar. FPL is aware that as more solar generation is added to its system, there will be a point where the peak hour to be served by non-solar generation will shift to a later hour. When this shift occurs, the firm capacity value of incremental solar projects will be reduced as the solar centers will generate less electricity at the later hour. FPL has analyzed this situation and has concluded that this shift to a later hour will not happen with the total solar generation in its system, including the proposed SolarTogether and 2020 SoBRA solar generation.

The attached table shows the annual projected capacity factor for the 2020 centers.

QUESTION:
Please refer to FPL's response to Staff's 4th Set of Interrogatories, No 31. Please explain why FPL included the SolarTogether project in the 2020 Project Plan and No 2020 Project Plan, when it has not yet been approved by the Commission.

RESPONSE:
FPL is asking the Commission for approval of 2020 SoBRA Project in this docket. At approximately the same time, FPL is asking for approval of the FPL SolarTogether Program ("Program") in Docket 20190061-EI. Neither the Program nor the 2020 SoBRA Project has been approved by the Commission. It would be reasonable to evaluate them in either order. FPL decided to evaluate the Program first, as some of the solar centers in the Program enter commercial operation service and it is the larger of the two programs. Therefore, FPL included the SolarTogether Program in the evaluation of the 2020 SoBRA Project.

QUESTION:
Please refer to FPL's response to Staff's 4th Set of Interrogatories, No 31. Please develop a revised No 2020 Project Plan and 2020 Project Plan resource plan that excludes the proposed SolarTogether project and includes the impact of the company's proposed demand-side management (DSM) goals from Docket No. 20190015-EG and additional incremental DSM after the goalsetting period.

a. Identify unit additions, dispatch order of units, retirements and changes for each year in the resource plan that differs from FPL's No 2020 Project Plan and FPL's 2020 Project Plan.
b. For both revised resource plans, provide annual and cumulative revenue requirements (in nominal and net present value) over the life of the project, a sensitivity of the fuel savings based upon a low fuel price forecast and a high fuel price forecast and a sensitivity of the analysis without CO2 emissions costs. As a part of this response, complete the table below and provide in electronic (Excel) format.
c. For both revised resource plans, please provide annual reserve margin data similar to Schedule 7 of the Ten-Year Site Plan, and complete the table and file it in electronic (excel) format.
d. For both revised resource plans, please provide an estimate of annual customer bills for a residential customer using 1,000 kWh/mo (in nominal and net present values).

RESPONSE:

a. Please refer to Interrogatory No. 49 from Staff's 6th Set for unit additions, retirements, and changes.

   Please note that FPL's production costing model does not use a dispatch order. Instead, commit and dispatch decisions are made by an optimization algorithm that captures factors not accounted for in any dispatch order, such as minimum up and down times, ramp rates, fuel limits, time-dependent solar generation, and battery operation, among others. Attachment I provides a list of units in order of their variable cost in $/MWh for 2021 which is the first year of operation for the 2020 SoBRA sites.

b. See Attachment II.
c. See Attachment III.
d. FPL does not have a long-term projection of bill impact by rate class. Attachment IV provides a projected system bill impact, not allocated by rate class, through the year 2050. In the testimony of FPL witness Edward Anderson, filed on September 3, 2019 in Docket 20190001-EI, FPL provided typical bill projections that reflect proposed base and fuel changes related to the SoBRA for the 2020 Project, scheduled to become effective by May 1, 2019.

QUESTION:

Please refer to FPL's response to Staff's 4th Set of Interrogatories, No 31. Please develop a revised 2020 Project Plan resource plan (No Battery Revised Resource Plan) that excludes both the proposed SolarTogether project and battery technology as a resource option using least cost methods. This resource plan should include the impact of the company's proposed DSM goals from Docket No. 20190015 and additional incremental DSM after the goalsetting period.

a. Identify unit additions, dispatch order of units, retirements and changes for each year in the resource plan.

b. Using the No Battery Revised Resource Plan, provide annual and cumulative revenue requirements (in nominal and net present value) over the life of the project, a sensitivity of the fuel savings based upon a low fuel price forecast, and a high fuel price forecast, and a sensitivity of the analysis without CO2 emissions costs. As a part of this response, complete the table below and provide in electronic (Excel) format.

c. Using the No Battery Revised Resource Plan, please provide annual reserve margin data similar to Schedule 7 of the Ten-Year Site Plan and complete the table and file it in electronic (excel) format.

d. Using the No Battery Revised Resource Plan, please provide an estimate of annual customer bills for a residential customer using 1,000 kWh/mo (in nominal and net present values).

RESPONSE:

a. Please see FPL's response to Staff's Sixth Set of Interrogatories, No. 49 for unit additions, retirements, and changes.

   Please note that FPL's production costing model does not use a dispatch order. Instead, commit and dispatch decisions are made by an optimization algorithm that captures factors not accounted for in any dispatch order, such as minimum up and down times, ramp rates, fuel limits, time-dependent solar generation and battery operation, among others. Attachment I provides a list of units in order of their variable cost in $/MWh for 2021 which is the first year of operation for the 2020 SoBRA sites.

b. See Attachment II. Please note that the only feasible alternative to meeting the reserve margin requirements in 2020 and 2021 are solar projects, as proposed in the 2020 SoBRA Project, or batteries as proposed in the "No 2020 Project" plan. The need in 2020 and 2021 is as high as 432 MWs in the years 2020 and 2021. Short-term power purchase agreements ("PPAs") are not believed by FPL to be available in this magnitude for these two years.

c. See Attachment III.

d. FPL does not have a long-term projection of bill impact by rate class. Attachment IV provides a projected system bill impact, not allocated by rate class, through the year 2050. In the testimony of FPL witness Edward Anderson, filed on September 3, 2019 in Docket 20190001, FPL provided typical bill projections that reflect proposed base and fuel changes related to the SoBRA for the 2020 Project, scheduled to become effective by May 1, 2019.

QUESTION:
Please refer to FPL's response to Staff's 4th Set of Interrogatories, No 31. Please provide a side-by-side comparison of the following resource plans listed below. As part of your response, provide the annual reserve margin values for each plan (with the generation-only reserve margin separate), and explain any differences between each of the plans, such as assumptions or methodology.

a. FPL's 2018 Ten-Year Site Plan
b. FPL's No 2020 Project Plan from EXH JE-3
c. FPL's 2020 Project Plan from EXH JE-3
d. Revised No 2020 Project Plan from Staff ROG No. 47
e. Revised 2020 Project Plan from Staff ROG No. 47
f. No Battery Revised Resource Plan from Staff ROG No. 48
g. FPL's Solar Together Resource Plan from Docket No. 20190061-EI

RESPONSE:
Please see Attachment I for a side-by-side comparison of the resource plans listed above.

The 2018 Ten-Year Site Plan (TYSP) used 2018 vintage assumptions while all the other resource plans listed above used 2019 vintage assumptions or 2019 TYSP assumptions. The differences in assumptions, when compared to the 2019 TYSP for sub-sections b, c, and g were due to the amount of new solar generation and whether FPL's proposed new goals for incremental DSM were included. However, in the development of sub-sections b, c, and g, FPL did not include new solar generation other than the near-term solar generation for which it is seeking approval.

The proposed new goals for incremental DSM had not been completed at the time the plans reflected in sub-sections b, c, and g plans were finalized so, these proposed new goals were not included in those plans. Staff's Interrogatory Nos. 47 and 48 requested the impact of the Company's proposed DSM goals and additional incremental DSM after the goalsetting period.

QUESTION:
Please refer to FPL's response to Staff Integratory No. 30.

a. Please explain how the 100 MW Battery was included in the resource optimization process as a resource option. As a part of this response, please provide a list of materials used in the development of the resource option and explain how assumptions regarding the battery were developed.
b. Please refer to FPL's responses to subparts b and c. Please explain how FPL can determine the 100 MW Battery is beneficial to the system if the variable system costs of the battery cannot be isolated from the overall variable system costs.
c. Please refer to FPL's responses to subparts c and subpart d. Provide the annual values over the life of the project in the following categories: Generation Capital, Long Term Capital Replenishment and Fixed O&M for the 100 MW Battery. As a part of this response, please explain all assumptions made for each category. Please provide this response in electronic (excel) format.
d. Please provide the annual and cumulative values over the life of the project assuming a 100 MW Combustion Turbine (CT) in the following categories: Generation Capital and Fixed O&M. Please provide this response in electronic (excel) format.
e. Please refer to FPL's responses to subparts c and d. If available, provide the annual values over the life of the project in the following categories: System Net Fuel, Startup + VOM, Emission for the 100 MW Battery and assumed 100 MW CT. As a part of this response please explain all assumptions made for each category.
f. Please provide a Levelized Cost of Energy (LCOE) analysis assuming a capacity factor between 5% and 50% for both a 100 MW Battery and 100 MW CT over the life of the project. Please provide in electronic (excel) format.
g. Please refer to FPL's table provided as responses to subparts d. Please provide the calculations for each category in electronic (excel) format with all formulas intact. As a part of this response, please describe all assumptions made for the calculations in each category.

RESPONSE:
a. Batteries were included as a potential resource option in both the EGEAS resource plan optimization model and the UPLAN production costing model. In both models, the parameters used to model the dispatch of the batteries were: capacity (MW), energy storage capacity (MWh), and energy conversion efficiency. The models dispatched the battery based on these parameters whenever it was economic to do so within the generation dispatch. The cost and energy conversion parameters for the batteries were developed by FPL's Engineering and Construction and Power Generation departments. The required energy storage capacity (MWh) for the batteries was developed by FPL's Resource Planning Department.

2020 100 MW Battery Projected Unit Financial Data *,**		
Duration:	2	Hours
Energy Capacity:	200	MWh
Conversion Loss Rate:	14	%
Book Life (Years):	10	years
Total Installed Cost (2020 $/kW):	538	
Direct Construction Cost (2020 $/kW):	531	
AFUDC Amount (2020 $/kW):	8	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	10.82	
Long Term Capital Replenishment ($/kW)	288	
Variable O&M (2020 $/MWH):	---	
K Factor:	1.29	

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes capital replacement and annual capital replenishment

b. The modeling did not isolate the individual benefits of the batteries. EGEAS selected batteries as part of the most economic resource plans for both the 2020 Project Plan and the No 2020 Project Plan cases, and their dispatch was modeled as described in (a) above. To identify the benefits of the batteries, FPL would have to develop resource plans without batteries, and this analysis was not performed as it was not deemed to be necessary in order to compare the 2020 Project Plan to the No 2020 Project Plan, as determining the cost-effectiveness of batteries was not the purpose of the analysis. The EGEAS model provided all the available generation options and their characteristics. EGEAS then chose the type and timing of generation options that resulted in the resource plan with the lowest CPVRR.

c. See Attachment I for annual revenue requirements and CPVRR.

When evaluating batteries as potential generation options for its resource plan, FPL developed a projection of initial on-going capital and O&M costs required to keep the battery operating at its nameplate rating over a 40-year operating life. While the book life of batteries is set at 10 years, the operating time frame of 40 years was chosen because batteries have to compete against combined cycle and combustion turbines that have a book life of 40 years and solar units that have a book life of 30 years.

The on-going costs for a battery consist of the following three components: annual O&M, annual capital expenditures, and capital replenishment costs. The O&M expenses are the annual expenses associated with maintaining the batteries, consisting primarily of payroll, preventive and corrective maintenance of all equipment, such as inverters, medium and high voltage, and balance of plant. Annual capital costs are equipment costs associated with replacing inverters and battery thermal management system (HVAC). Capital replenishment costs consist primarily of battery cell replacements, which are expected to take place on annual basis for the 40-year operating period. These annual expenditures ensure that the performance of the battery is maintained at the original level of performance.

d. See Attachment II for annual revenue requirements and CPVRR.

   The costs of the combustion turbines are based on a set of two combustion turbines, which is the smallest size for which FPL has cost estimates, prorated to 100 MW.

e. Please see attachment III. Please note that the battery itself does not consume fuel and produce emissions. FPL did not assume any VOM costs or start-up costs. All operating costs were included in the Fixed O&M charge.

f. See Attachment IV and Attachment V.

   Both combustion turbines and batteries were provided as potential generation options into the EGEAS optimization model. Batteries have some advantages over combustion turbines in that they can be built faster, and can be built in smaller increments and may therefore be chosen by the optimization model as part of the most cost-effective resource plan. The model selected the most economic mix and timing of resources for both the 2020 Project Plan and No 2020 Project Plan.

   FPL does not believe that a levelized cost of electricity comparison, also known as a screening curve analysis, is the proper way to compare resource options, as this approach ignores the system impact of these resources. As requested, FPL computed a table with the comparison requested (see below). The costs of the combustion turbines are based on a set of two combustion turbines, which is the smallest size for which FPL has cost estimates, prorated to 100 MW.

Battery

Capacity Factor	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%
Total cost levelized (millions)	5	5	5	5	6	6	6	6	6	6
levelized cost $/MWH	1,397	715	488	375	306	261	228	204	185	170

Combustion Turbine

Capacity Factor	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%
Total cost levelized (millions)	8	9	11	13	15	17	19	21	22	24
levelized cost $/MWH	173	108	86	75	69	64	61	59	57	56

Battery Data

Capacity	100	MW
Duration	2	
Energy capacity	200	MWH
Conversion loss rate	14%	
In-service year	2020	

Combustion Turbine

Capacity	100	MW
Heat rate	9,944	btu/kWH
VOM year 1	0.02	$/MWH
VOM escalation	0.025	
In-service year	2023	

g. See table below and Confidential Attachments VI - IX for sub-part g. The capital costs of the combustion turbine were provided by FPL's Engineering and Construction Business Unit. The operation and maintenance costs were provided by FPL's Power Generation Business Unit.

2023 100 MW CT Projected Unit Financial Data *,**		
Book Life (Years):	40	years
Total Installed Cost (2023 $/kW):	490	
Direct Construction Cost (2023 $/kW):	470	
AFUDC Amount (2023 $/kW):	20	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	8.06	
Variable O&M (2023 $/MWH):	0.02	
K Factor:	1.11	

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes Capital Replacement

QUESTION:
Please refer to FPL's response to Staff Integratory No. 30.

a. Please explain how the 100 MW Battery was included in the resource optimization process as a resource option. As a part of this response, please provide a list of materials used in the development of the resource option and explain how assumptions regarding the battery were developed.
b. Please refer to FPL's responses to subparts b and c. Please explain how FPL can determine the 100 MW Battery is beneficial to the system if the variable system costs of the battery cannot be isolated from the overall variable system costs.
c. Please refer to FPL's responses to subparts c and subpart d. Provide the annual values over the life of the project in the following categories: Generation Capital, Long Term Capital Replenishment and Fixed O&M for the 100 MW Battery. As a part of this response, please explain all assumptions made for each category. Please provide this response in electronic (excel) format.
d. Please provide the annual and cumulative values over the life of the project assuming a 100 MW Combustion Turbine (CT) in the following categories: Generation Capital and Fixed O&M. Please provide this response in electronic (excel) format.
e. Please refer to FPL's responses to subparts c and d. If available, provide the annual values over the life of the project in the following categories: System Net Fuel, Startup + VOM, Emission for the 100 MW Battery and assumed 100 MW CT. As a part of this response please explain all assumptions made for each category.
f. Please provide a Levelized Cost of Energy (LCOE) analysis assuming a capacity factor between 5% and 50% for both a 100 MW Battery and 100 MW CT over the life of the project. Please provide in electronic (excel) format.
g. Please refer to FPL's table provided as responses to subparts d. Please provide the calculations for each category in electronic (excel) format with all formulas intact. As a part of this response, please describe all assumptions made for the calculations in each category.

RESPONSE:
a. Batteries were included as a potential resource option in both the EGEAS resource plan optimization model and the UPLAN production costing model. In both models, the parameters used to model the dispatch of the batteries were: capacity (MW), energy storage capacity (MWh), and energy conversion efficiency. The models dispatched the battery based on these parameters whenever it was economic to do so within the generation dispatch. The cost and energy conversion parameters for the batteries were developed by FPL's Engineering and Construction and Power Generation departments. The required energy storage capacity (MWh) for the batteries was developed by FPL's Resource Planning Department.

2020 100 MW Battery Projected Unit Financial Data *,**		
Duration:	2	Hours
Energy Capacity:	200	MWh
Conversion Loss Rate:	14	%
Book Life (Years):	10	years
Total Installed Cost (2020 $/kW):	538	
Direct Construction Cost (2020 $/kW):	531	
AFUDC Amount (2020 $/kW):	8	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	10.82	
Long Term Capital Replenishment ($/kW)	288	
Variable O&M (2020 $/MWH):	---	
K Factor:	1.29	

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes capital replacement and annual capital replenishment

b. The modeling did not isolate the individual benefits of the batteries. EGEAS selected batteries as part of the most economic resource plans for both the 2020 Project Plan and the No 2020 Project Plan cases, and their dispatch was modeled as described in (a) above. To identify the benefits of the batteries, FPL would have to develop resource plans without batteries, and this analysis was not performed as it was not deemed to be necessary in order to compare the 2020 Project Plan to the No 2020 Project Plan, as determining the cost-effectiveness of batteries was not the purpose of the analysis. The EGEAS model provided all the available generation options and their characteristics. EGEAS then chose the type and timing of generation options that resulted in the resource plan with the lowest CPVRR.

c. See Attachment I for annual revenue requirements and CPVRR.

When evaluating batteries as potential generation options for its resource plan, FPL developed a projection of initial on-going capital and O&M costs required to keep the battery operating at its nameplate rating over a 40-year operating life. While the book life of batteries is set at 10 years, the operating time frame of 40 years was chosen because batteries have to compete against combined cycle and combustion turbines that have a book life of 40 years and solar units that have a book life of 30 years.

The on-going costs for a battery consist of the following three components: annual O&M, annual capital expenditures, and capital replenishment costs. The O&M expenses are the annual expenses associated with maintaining the batteries, consisting primarily of payroll, preventive and corrective maintenance of all equipment, such as inverters, medium and high voltage, and balance of plant. Annual capital costs are equipment costs associated with replacing inverters and battery thermal management system (HVAC). Capital replenishment costs consist primarily of battery cell replacements, which are expected to take place on annual basis for the 40-year operating period. These annual expenditures ensure that the performance of the battery is maintained at the original level of performance.

d. See Attachment II for annual revenue requirements and CPVRR.

   The costs of the combustion turbines are based on a set of two combustion turbines, which is the smallest size for which FPL has cost estimates, prorated to 100 MW.

e. Please see attachment III. Please note that the battery itself does not consume fuel and produce emissions. FPL did not assume any VOM costs or start-up costs. All operating costs were included in the Fixed O&M charge.

f. See Attachment IV and Attachment V.

   Both combustion turbines and batteries were provided as potential generation options into the EGEAS optimization model. Batteries have some advantages over combustion turbines in that they can be built faster, and can be built in smaller increments and may therefore be chosen by the optimization model as part of the most cost-effective resource plan. The model selected the most economic mix and timing of resources for both the 2020 Project Plan and No 2020 Project Plan.

   FPL does not believe that a levelized cost of electricity comparison, also known as a screening curve analysis, is the proper way to compare resource options, as this approach ignores the system impact of these resources. As requested, FPL computed a table with the comparison requested (see below). The costs of the combustion turbines are based on a set of two combustion turbines, which is the smallest size for which FPL has cost estimates, prorated to 100 MW.

Battery

Capacity Factor	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%
Total cost levelized (millions)	5	5	5	5	6	6	6	6	6	6
levelized cost $/MWH	1,397	715	488	375	306	261	228	204	185	170

Combustion Turbine

Capacity Factor	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%
Total cost levelized (millions)	8	9	11	13	15	17	19	21	22	24
levelized cost $/MWH	173	108	86	75	69	64	61	59	57	56

Battery Data

Capacity	100	MW
Duration	2	
Energy capacity	200	MWH
Conversion loss rate	14%	
In-service year	2020	

Combustion Turbine

Capacity	100	MW
Heat rate	9,944	btu/kWH
VOM year 1	0.02	$/MWH
VOM escalation	0.025	
In-service year	2023	

g. See table below and Confidential Attachments VI - IX for sub-part g. The capital costs of the combustion turbine were provided by FPL's Engineering and Construction Business Unit. The operation and maintenance costs were provided by FPL's Power Generation Business Unit.

2023 100 MW CT Projected Unit Financial Data *,**		
Book Life (Years):	40	years
Total Installed Cost (2023 $/kW):	490	
Direct Construction Cost (2023 $/kW):	470	
AFUDC Amount (2023 $/kW):	20	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	8.06	
Variable O&M (2023 $/MWH):	0.02	
K Factor:	1.11	

* $/kW values are based on Summer capacity.
** Levelized value for Fixed O&M also includes Capital Replacement

QUESTION:
Please refer to FPL's response to Staff's 4th Set of Interrogatories, No 31. Please detail how the gas transportation costs were determined. As part of this response, please provide the annual amount of subscribed firm gas transportation capacity for the company in MCF/d for all resource plans listed below.

a. FPL's 2018 Ten-Year Site Plan
b. FPL's No 2020 Project Plan from EXH JE-3
c. FPL's 2020 Project Plan from EXH JE-3
d. Revised No 2020 Project Plan from Staff ROG No. 47
e. Revised 2020 Project Plan from Staff ROG No. 47
f. No Battery Revised Resource Plan from Staff ROG No. 48
g. FPL's Solar Together Resource Plan from Docket No. 20190061-EI

RESPONSE:
FPL has contracted for the amount of firm gas transport shown in the table below, with the last increment added in 2020.

	Total Firm Gas Under Contract-Summer *
	MMCF/day
2020	2,569
2021	2,569
2022	2,569
2023	2,569
2024	2,569
2025	2,569
2026	2,569
2027	2,569
2028	2,569
2029	2,569
2030-2050	2,569

* *Includes firm gas capacity under contract under FGT, Gulfstream and Sabal Trail*

FPL determines the amount of total firm gas transport required for each resource plan by modeling each one in the UPLAN production costing model and determining its total system gas use on the summer peak day. The amount of gas transport already under contract, as shown on the table above, is subtracted from the total firm gas use on the peak day to determine the incremental amount of firm gas transport that would be needed for each resource plan. FPL has not acquired the required incremental firm gas transport for any of them. Therefore, the amount of firm gas transportation under subscription is the same for all of the resource plans identified in (a) through (g).

QUESTION:
Please refer to Staff Interrogatory No. 47. Please describe FPL's gas transportation purchase process. The description should include information related to minimum purchase size, contract commitment duration, etc.

RESPONSE:
FPL is continuously evaluating the need for additional gas transportation based on the most current forecast of future natural gas burns. Since the major gas pipelines serving Florida are fully subscribed (with the exception of some seasonal availability), any significant gas transportation need would have to be served by a new pipeline or a pipeline expansion. This process can take up to five years to complete depending on the complexity of the pipeline project. The pipeline will require a term commitment of 20-30 years for this type of project.

If a forecast results in increased natural gas demand, FPL will evaluate all of the pipeline delivery alternatives in order to secure the most cost effective gas transportation contract based on the quantity and timing of the need. If the need is associated with the addition of a new natural gas generation plant, FPL can enter into a firm transportation agreement with a pipeline subject to FPL receiving all regulatory approvals to proceed with construction of the generation plant.

QUESTION:
Please explain the process FPL uses to determine the AC/DC ratio for each project site. As part of your response, provide the necessary ratio to account for losses from the inverter, and if the final ratio selected is higher than this, explain why and provide the amount of solar spillage that occurs.

RESPONSE:
The process FPL used to determine DC/AC ratios was structured to maximize benefit to FPL's customers. Using a proxy site, FPL performed iterative energy production calculations based on a number of layout scenarios with varying combinations of DC/AC ratios and ground coverage ratios ("GCR"). These are the two primary parameters that drive solar facility energy production. Construction costs were also developed for each scenario. Using the energy production results and cost estimates, FPL determined the CPVRR for each scenario and identified the range of DC/AC ratios that provided the greatest benefit to FPL's customers. The range of DC/AC ratios was used as one of the inputs in developing specific layouts to accommodate the unique characteristics for each site.

The DC/AC ratio necessary to account for the electrical losses from the PV modules to the point of interconnection and deliver exactly 74.5 MWac for a typical 2020 Project solar energy center is 1.1. This DC/AC ratio accounts for electrical losses from the DC collection system, the inverters, the medium voltage transformers, the AC collection system, and the main transformer. However, it would be non-economic to use this DC/AC ratio in the design of a solar facility. A higher DC/AC ratio is required to maximize value over the life of the facility to account for factors such as module degradation and daily/seasonal variations in solar irradiance. The DC/AC ratios FPL used for the 2020 Project solar energy centers provide a balance between construction costs and energy production to maximize value to FPL's customers. Accordingly, the concept of "spillage" is not applicable to PV facilities when the DC/AC ratios have been developed as outlined above.

QUESTION:
Please refer to FPL's response to Staff's First Set of Interrogatories, No. 77 and 106 in Docket No. 20190061-EI. Please explain how savings for gas transportation begin in 2026 if the FPL SolarTogether Plan reduces gas transportation by 105 mcf/day delaying need for summer capacity until 2029.

RESPONSE:
The FPL SolarTogether Plan reflects a reduced need for firm gas transport by 105 MMCF per day. Under the No ST Plan, there is a deficit of firm gas transport starting in 2026, so FPL assumed that it would contract for firm gas transport in 2027. While FPL's need for firm gas continues to increase after 2027 reaching a level of 159 MMCF/day by 2030, the FPL SolarTogether Program was credited with a maximum reduction of 105 MMCF/day.

DECLARATION

I sponsored the answers to Interrogatory No. 53 from **STAFF'S SIXTH SET OF INTERROGATORIES (NOS. 43-54)** to Florida Power & Light Company in Docket No. 20190001-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.

William F. Brannen

Date: September 12, 2019

DECLARATION

I sponsored the answer to Interrogatory Nos. 43 through 51 and 54 from **STAFF'S SIXTH SET OF INTERROGATORIES (NOS. 43-54)** to Florida Power & Light Company in Docket No. 20190001-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.

Juan E. Enjamio

Date: 9/12/2019

DECLARATION

I sponsored the answers to Interrogatory No. 52 from **STAFF'S SIXTH SET OF INTERROGATORIES (NOS. 43-54)** to Florida Power & Light Company in Docket No. 20190001-EI. The response is 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.

Heather Stubblefield

Heather Stubblefield

Date: 9/16/19

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FPL's Response to Staff's Seventh Set of Interrogatories, No. 55b

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 88
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Renae B. Deaton

QUESTION:

Please refer to the Direct Testimony of Robert Coffey, as filed on September 3, 2019, in DN 20190001-EI. At Page 7, Lines 8-14, witness Coffey generally describes the insurance arrangements that FPL has with the Nuclear Electric Insurance Limited ("NEIL"), as pertaining to the extended outage in 2019 at St. Lucie Unit 1.

a. **Please clarify that any claim(s) FPL is pursuing with NEIL only pertains to repair-related costs, and not for replacement fuel costs attributable to this outage.**
b. **Please clarify that none of the repair-related costs are included in the cost recovery schedules that witness Renae B. Deaton sponsored, as filed on September 3, 2019, in DN 20190001-EI.**

RESPONSE:

a. FPL has filed a claim with NEIL for repair-related costs only. FPL did not file a claim for replacement fuel costs because the event was subject to a 12-week duration deductible which was not met.
b. No repair-related costs are included in any clause schedules.

DECLARATION

I sponsored the answer to Interrogatory No. 55(b) from **STAFF'S SEVENTH SET OF INTERROGATORIES (NO. 55)** to Florida Power & Light Company in Docket No. 20190001-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.

RBDeaton

Renae B. Deaton

Date: 9.25.19

89

FPL's Response to Staff's Fourth Request for Production of Documents, No. 5

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 89
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Renae B. Deaton

QUESTION:
Please refer to the Testimony of Florida Power & Light witness Renae B. Deaton, dated September 3rd, 2019, filed in docket No. 20190001-EI. Please provide alternative Exhibits RBD-7, RBD-8, and RBD-9, which exclude the 2020 SolarTogether Credit of $31,975,895.

RESPONSE:
Please see files provided:

"RBD-7 exc SolarTogether"
"RBD-8 exc SolarTogether"
"RBD-9 exc SolarTogether"

Documents responsive to this request are provided as Bates Nos. FCR-19-029115 through FCR-19-029132.

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DEF's Response to Staff's First Set of Interrogatories, Nos. 1-8

CONFIDENTIAL DN. 03322-2019

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 90
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Jim McClay (1-7)Christopher A. Menendez (8)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 20190001-EI Dated: March 19, 2019

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-8)

Duke Energy Florida, LLC ("DEF") responds to the Staff of the Florida Public Service Commission's ("Staff") First Set of Interrogatories to DEF (Nos. 1-8) as follows:

INTERROGATORIES

1. For each Request for Proposal (RFP) for coal issued in 2018 by or on behalf of DEF, list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

Answer:

Please see the attached files: 2019 PS ROG 1-1 CONFIDENTIAL February 2018 Spot Solicitation; 2019 PS ROG 1-1 CONFIDENTIAL April 2018 Spot Solicitation; and 2019 PS ROG 1-1 CONFIDENTIAL September 2018 Fall Term RFP for the lists of bids received in response to verbal spot solicitations conducted February 8, 2018, and April 4, 2018, as well as to the Term RFP issued on September 17, 2018 bearing bates numbers DEF-19FL-FUEL-000001 through DEF-19FL-FUEL-000004.

The attachments are confidential; redacted versions are attached hereto and unredacted copies have been filed with the Florida Public Service Commission ("Commission") along with DEF's Request for Confidential Classification.

2. Please describe the action taken for each bid identified in response to Interrogatory No. 1. Include in your response an explanation of the evaluation process and how successful proposals were selected.

Answer:

The action taken on each bid identified is contained in the response to Interrogatory No. 1.

The evaluations took into consideration factors including, but not limited to, the following:

a. conformity to the technical and commercial aspects of the specifications (e.g., coal specifications, delivery schedules, warranties, etc.);
b. coal quality and quantity assurances (or guarantees) by the bidder;
c. prices and conditions of pricing;
d. any exceptions to the specifications and resulting penalties;
e. supplier operations and/or shipping capabilities;
f. previous supplier performance;
g. supplier flexibility (i.e. quantity, term, location); and
h. any other considerations applicable under the circumstances.

DEF produced an evaluated delivered cost per MMbtu for each coal and selected the appropriate coals based on this complete evaluation.

3. During 2018, did DEF experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.

Answer:

During 2018, DEF incurred detention and demurrage charges as a result of river barge, Gulf barge, terminal, and/or train loading or unloading delays. The general causes for the loading and/or unloading delays include, but are not limited to, weather impacts and operational considerations. Detention and demurrage charges are not assigned nor categorized by event, rather attributable to general delays, so the specific charges for each event type cannot be provided. For detention and demurrage charges DEF incurred for 2018, please see attachment titled 2019 PS ROG 1-3 CONFIDENTAL DEF 2018 Detention and Demurrage Costs bearing bates numbers DEF-19FL-FUEL-000005.

This document is confidential; a redacted version is attached hereto and an unredacted copy has been filed with the Commission along with DEF's Request for Confidential Classification.

4. For each RFP for natural gas issued in 2018 by DEF, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline used for delivery.

Answer:

Please see the attachments bearing bates numbers DEF-? through DEF-? for the natural gas requests issued during 2018.

Please see the attachment bearing bates number bearing bates numbers DEF-19FL-FUEL-000006 through bearing bates numbers DEF-19FL-FUEL-000010 for the list of bids and the response summaries for each request. The attachment bearing bates number is

confidential; a redacted version is attached hereto and an unredacted copy has been filed with the Commission along with DEF's Request for Confidential Classification dated March 20, 2019.

5. Please describe the action taken for each bid identified in response to Interrogatory No. 4. Include in your response an explanation of the evaluation process and how successful proposals were selected.

Answer:

Please see confidential attachments bearing bates numbers DEF-19FL-FUEL-000006 through bearing bates numbers DEF-19FL-FUEL-000010provided in response to Question 4. In summary, as part of DEF's on-going strategy to maintain a diverse, secure, and competitively priced natural gas supply portfolio to meet its gas generation needs, DEF conducts periodic gas supply RFPs and solicitations to procure natural gas supply over time. DEF requests specific time periods and locations that represent firm natural gas supply receipt point locations on DEF's firm transportation agreements. As outlined in the referenced attachments, bids were evaluated and selected based on credit, economics, location, term, and supply requirements.

6. In 2018, did DEF participate in any capacity discussions or bid for any firm pipeline capacity during "open season?" Please explain your response and identify the pipeline companies.

REDACTED

Answer:

DEF engages in ongoing discussions with various gas suppliers, pipelines and existing storage providers to stay abreast of developments and potential gas pipeline opportunities. During 2018, [redacted]

7. In 2018, did DEF participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

Answer:

DEF engages in ongoing discussions with various gas suppliers, pipelines and existing storage providers to stay abreast of developments and potential gas storage opportunities. During 2018, DEF did not bid for any new gas storage in 2018.

8. For the purpose of this interrogatory, please refer to Duke Energy Florida's December 2018 A Schedule filing, and specifically to Schedule A2(C), Line 13 (End of Period True Up amounts), and the Columns with Year-To-Date amounts. Please explain the discrepancy between the actual and projected amounts, including in your response the primary reason(s) for the under-recovered balance.

Answer:

The $54.4 million difference between actual and projected amounts on Schedule A2(C), Line 13 is due to increased actual fuel expense compared to projection. This is primarily due to increased natural gas generation and purchased power expense of approximately $97.6 million partially offset by coal expense of approximately $44.7 million, driven in part by a shift from coal to natural gas generation and purchased power

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 20th day of March, 2019, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JIM MCCLAY, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory numbers 1 through 7 of STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-8) in Docket No. 20190001-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 20th day of March, 2019.

Jim McClay

Jim McClay

Mary B Vicknair

Notary Public
State of North Carolina

My Commission Expires: 09/21/2022

MARY B VICKNAIR
NOTARY PUBLIC
Davie County
North Carolina
My Commission Expires Sept. 21, 2022

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 19th day of March, 2019, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared CHRISTOPHER A. MENENDEZ, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory number 8 of STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 1-8) in Docket No. 20190001-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 March, 2019.

Christopher A. Menendez

Notary Public
State of Florida, at Large

My Commission Expires: June 28, 2019

EVALUATION/REVIEW OF SPOT COAL FOR March 1, 2018 - June 30, 2018
(February 2018 Verbal Coal Supply Solicitation)

REDACTED

Station: CRYSTAL RIVER 4&5

Docket No.20190001-EI
DEF's Response to Staff's 1st Set of Interrogatories (1-8)
PS ROG 1-1 DEF-19FL-FUEL

Sales Co.	Producer	Start Date	End Date	Rail Barge	Region	March Vol	April Vol	May Vol	June Vol	Btu	Moist %	Ash %	Sul %	Grd	Vol %	AFT	Chl	LBS SO2	Offer Price $/Ton	Total Freight Cost	Delivered $/Ton	$/MmBtu Delvd Q4/M, $/Q Adj	Comments
[redacted]																							

20190001.EI Staff Hearing Exhibits 00105

EVALUATION/REVIEW OF SPOT COAL FOR June 1, 2018 - September 30, 2018
(April 2018 Verbal Coal Supply Solicitation)

REDACTED

Station: CRYSTAL RIVER 4&5

Docket No.20190001-EI
DEF's Response to Staff's 1st Set of Interrogatories (1-8)
PS ROG 1-1 DEF-19FL-FUEL

Sales Co	Producer	Start Date	End Date	Rail Range	Region	May Vol	June Vol	July Vol	August Vol	September Vol	Btu	Moist %	Ash %	Sul %	Grd	Vol %	AFT	Chl	LBS SO2	Offer Price $/Ton	Total Freight Cost	Delivered $/Ton	$/MmBtu Delvd O&M, SO2 Adj	Comments
[redacted]																								

20190001.EI Staff Hearing Exhibits 00106

EVALUATION/REVIEW OF TERM COAL FOR OCTOBER 1, 2018 - DECEMBER 31, 2021
(September 17, 2018 FALL TERM RFP)

REDACTED

Docket No.20190001-EI
DEF's Response to Staff's 1st Set of Interrogatories (1-8)
PS ROG 1-1DEF-19FL-FUEL

Station: **Crystal River 4&5**

Bid #	Year	Counterparty	Region	Mode	Annual Volume	Btu/lb	SO2/mmBt	Ash %	FOB Point	Mine $ /ton	Barge	Transportation $/ton Terminal	Truck	Rail	Other	Delivered $/ton	$/MmBtu Delvd O&M, SO2 Adj	Comments
[redacted]																		

20190001.EI Staff Hearing Exhibits 00107

EVALUATION/REVIEW OF TERM COAL FOR OCTOBER 1, 2018 - DECEMBER 31, 2021
(September 17, 2018 FALL TERM RFP)

REDACTED

Station: **Crystal River 4&5**

Docket No.20190001-EI
DEF's Response to Staff's 1st Set of Interrogatories (1-8)
PS ROG 1-1 DEF-19FL-FUEL

Bid #	Year	Counterparty	Region	Mode	Annual Volume	Btu/lb	SO2/mmBt	Ash %	FOB Point	Mine $ /ton	Barge	Transportation $/ton Terminal	Truck	Rail	Other	Delivered $/ton	$/MmBtu Delvd O&M, SO2 Adj	Comments
[redacted]																		

20190001.EI Staff Hearing Exhibits 00108

REDACTED

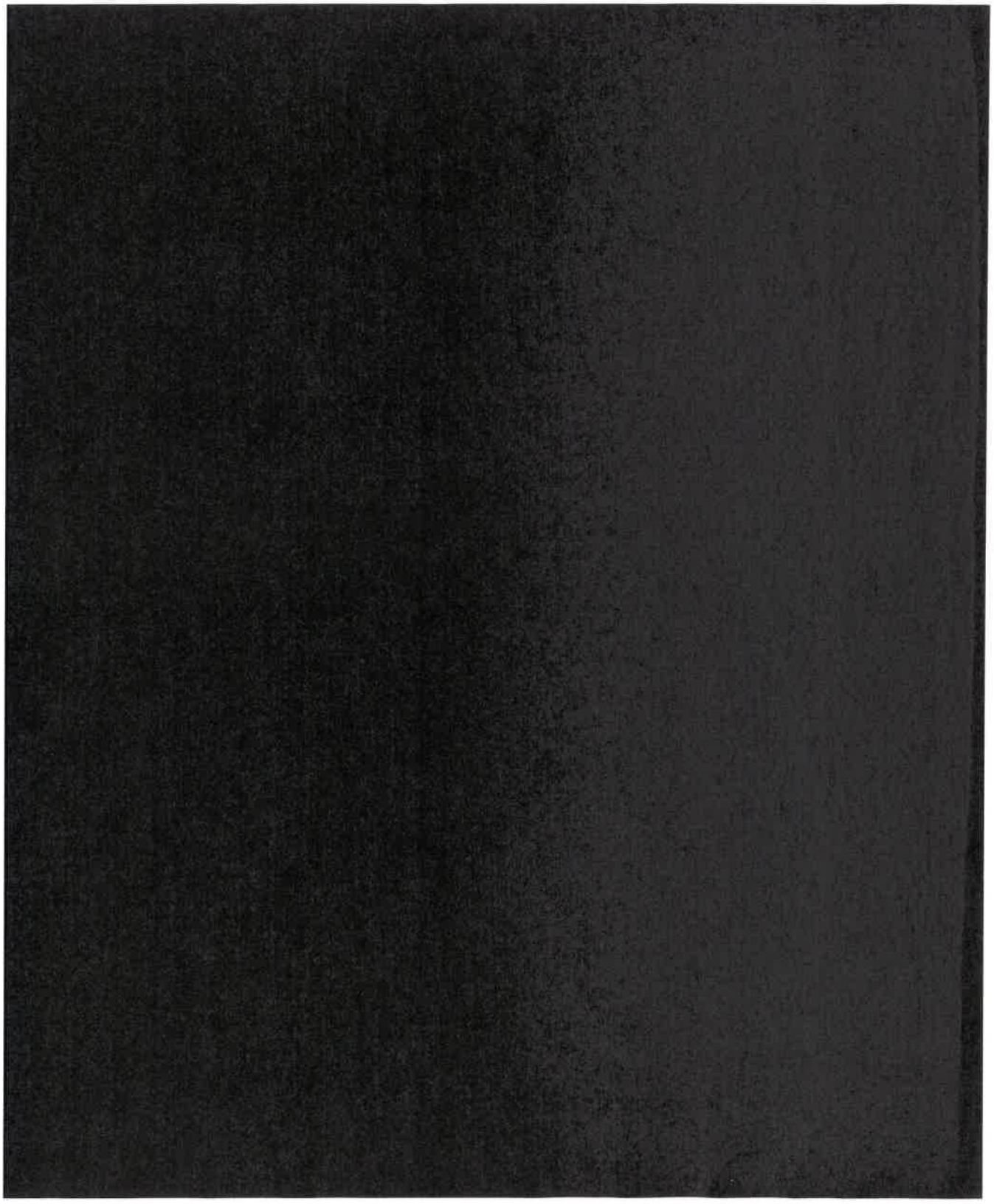
DEF Coal Demurrage and Detentions January - December 2018

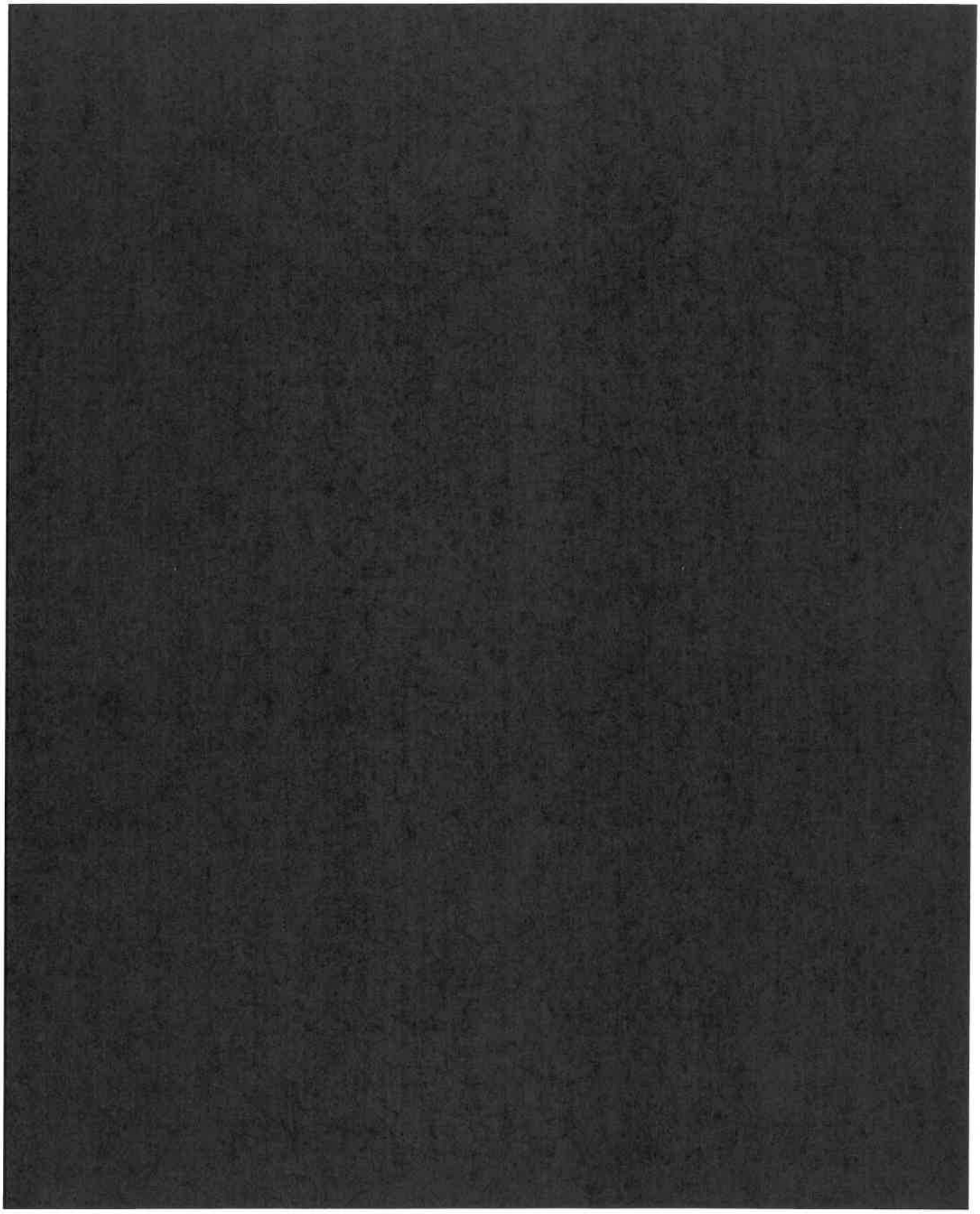
Docket No.20190001-EI
DEF's Response to Staff's 1st Set of Interrogatories (1-8)
PS ROG 1-3 DEF-19FL-FUEL

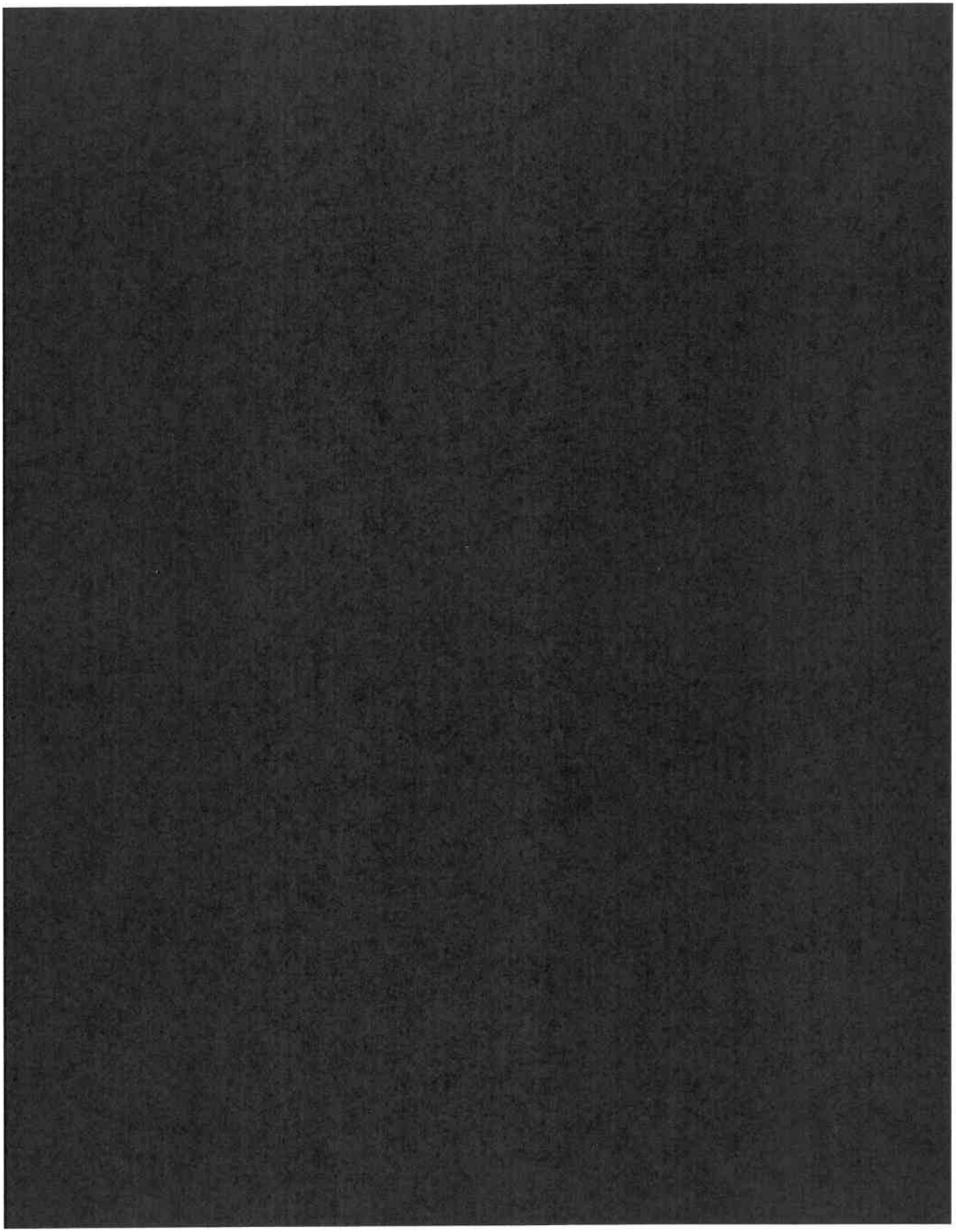
Counterparty	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
EMI PA INC													
FLNORTHERN													
IMT													
INGRAM BARGE COMPANY													
KIRBY OCEAN TRANSPORT CO													
Grand Total	$ 134,884.57	$ 9,420.00	$ 1,410,183.27	$ 877,610.07	$ 3,358,208.73	$ 1,879,531.06	$ 3,206,987.84	$ 1,082,530.58	$ 866,551.55	$ 2,588,336.46	$ 336,995.16	$ 707,308.04	$ 16,458,547.33

20190001.EI Staff Hearing Exhibits 00109

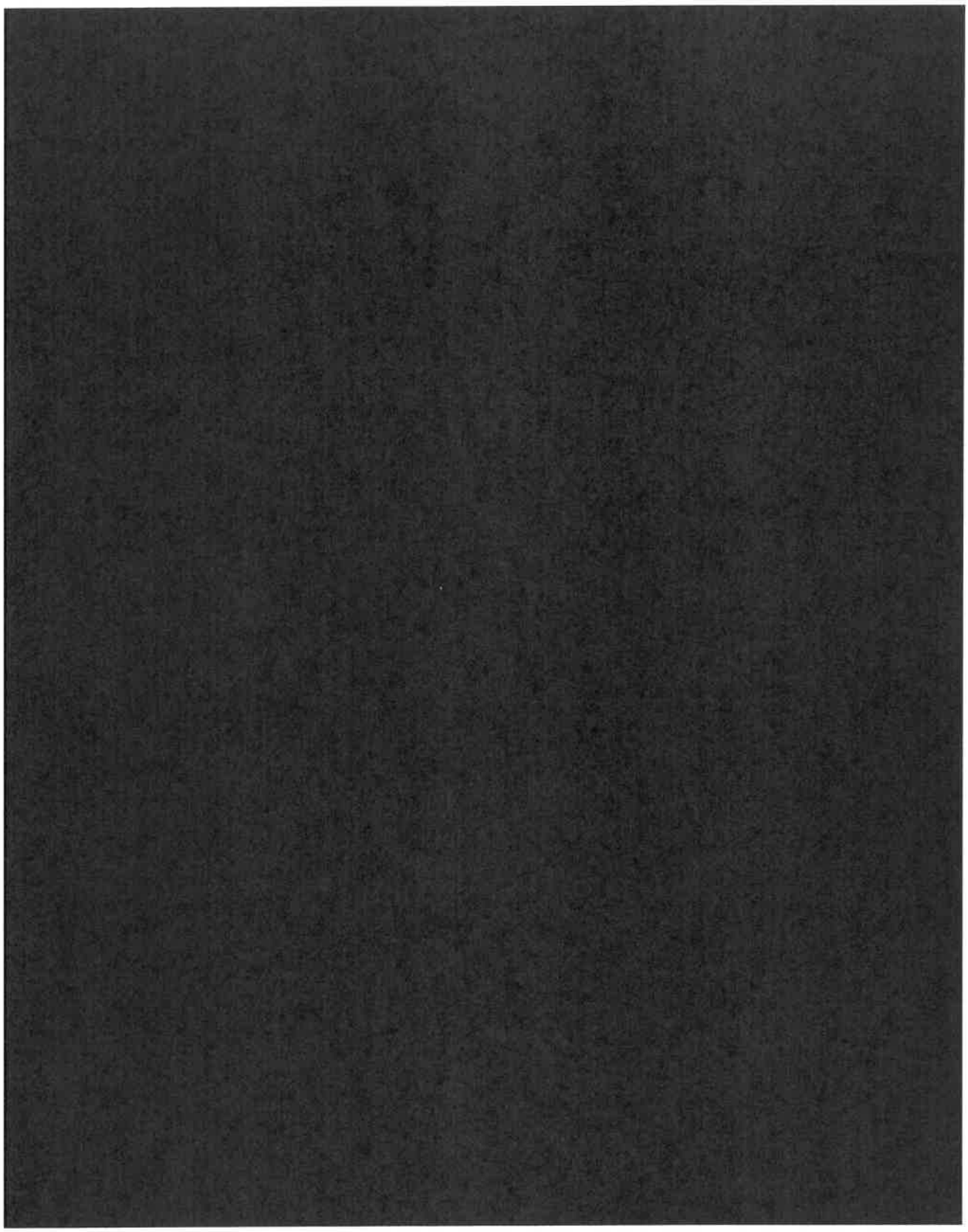
DUKE ENERGY.







REDACTED



REDACTED

Package #1 – Southeast Supply Header's ("SESH") Centerpoint, Gulf South, Columbia Gulf, Tiger, Texas Eastern and/or TGP (SESH Locations #8,3001/#8,3003/#8,3004/#8,3014/#8,3005/#8,3008)

COMPANY (Seller)	DELIVERY POINT	SUPPLY SOURCE Onshore, Offshore or LNG (% from Supply Source)	TERM		VOLUME		PRICING							NOTES/OTHER
			Start	Termination	MIN (Dth/day)	MAX (Dth/day)	INDEX (NYMEX LDS / IFERC / Argus)	Location (i.e. "IFERC Transco Zone 4" or "N/A" for NYMEX LDS)	Price Adder or (Discount) to LDS, IFERC or Argus	Reservation / Demand Fee ($ per Dth)	Average IFERC Basis for Term or "0" for NYMEX LDS	Price Adder (Discount) to LDS or IF	Estimated Total Basis	Rank	
[redacted]															

COMPANY (Seller)	DELIVERY POINT	SUPPLY SOURCE Onshore, Offshore or LNG (% from Supply Source)	TERM		VOLUME		PRICING							NOTES/OTHER
			Start	Termination	MIN (Dth/day)	MAX (Dth/day)	INDEX (NYMEX LDS / IFERC)	Location (i.e. "IFERC Transco Zone 4" or "N/A" for NYMEX LDS)	Price Adder or (Discount) to LDS, IFERC or Argus	Reservation / Demand Fee ($ per Dth)	Average IFERC Basis for Term or "0" for NYMEX LDS	Price Adder (Discount) to LDS or IF	Estimated Total Basis	Rank	
[redacted]															

COMPANY (Seller)	DELIVERY POINT	SUPPLY SOURCE Onshore, Offshore or LNG (% from Supply Source)	TERM		VOLUME		PRICING							NOTES/OTHER
			Start	Termination	MIN (Dth/day)	MAX (Dth/day)	INDEX (NYMEX LDS / IFERC)	Location (i.e. "IFERC Transco Zone 4" or "N/A" for NYMEX LDS)	Price Adder or (Discount) to LDS, IFERC or Argus	Reservation / Demand Fee ($ per Dth)	Average IFERC Basis for Term or "0" for NYMEX LDS	Price Adder (Discount) to LDS or IF	Estimated Total Basis	Rank	
[redacted]															

20190001.EI Staff Hearing Exhibits 00114

91

DEF's Response to Staff's Second Set of Interrogatories, Nos. 9-17

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 91
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Christopher A. Menendez (9-17)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 20190001-EI Dated: April 1, 2019

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 9-17)

Duke Energy Florida, LLC ("DEF") responds to the Staff of the Florida Public Service Commission's ("Staff") Second Set of Interrogatories to DEF (Nos. 9-17) as follows:

INTERROGATORIES

9. Please describe the steps the Company undertook to prepare the fuel price forecast the Company prepared to support its 2019 projections, as filed on August 24, 2018, in Docket No. 20180001. Discuss in your response when these steps were started and when these steps were concluded, and how the timeline for preparing this forecast compared to the timeline for preparing the similar forecasts for 2017 or 2018.

Answer:

DEF prepared its 2019 fuel price forecast as follows:

1. Accumulated model input data listed in ROG #12 below.

2. Performed a production cost model to forecast system operation and generation.

3. Analyzed model results for reasonableness.

4. Applied inventory, capacity and fixed costs to model results to determine accounting cash flows and expected fuel costs.

DEF started its 2019 fuel price forecast approximately 6/15/18 and ended approximately 6/28/18. Timelines for the 2017 and 2018 fuel price forecasts generally started and ended during the same time frame as the 2019 fuel price forecast. The timeline does not include the preparation and filing of the annual Actual/Estimated and Projection Fuel Filings.

10. How often are fuel price forecasts prepared? Discuss in your response what triggers, or market observations would prompt the Company to update its fuel price forecast.

Answer:
Fuel price forecasts are generally prepared on a quarterly basis. Triggers or market observations that would cause DEF to update its fuel forecast are extreme market conditions which would abnormally impact DEF operations.

11. If known, identify the date the next fuel price forecast is scheduled to be prepared.

Answer:
DEF currently expects the new fuel forecast to be prepared in April 2019.

12. Please identify the forecasting sources that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

Answer:
The main sources of input to the fuel forecast model are as follows:

1. Hourly (MW) Load Forecast
2. Generation Portfolio Capabilities and Constraints (i.e. ramp rates, unit min/max loadings, min up/down times, ancillary, heat rates, startup fuel, variable O&M and historical forces outage rates)
3. Hourly Solar Energy Forecast
4. Hourly QF Generation Energy Forecast
5. Fuel Transportation Cost Forecast
6. Commodity Price and Fuel Inventory Forecasts for natural gas, coal and oil
7. Generation Planned Outage Schedule
8. Planned retirements or additions
9. Power Price Forecast

13. Were any of the sources identified in the response to Interrogatory number 12 new or different than the sources used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

Answer:
No.

14. Please identify the forecasting assumptions that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

Answer:
The forecast assumes weather normal load requirements and operations for DEF, and fuel curves with a COB date of 6/15/18.

15. Were any of the assumptions identified in the response to Interrogatory number 14 new or different than the assumptions used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

Answer:
No.

16. Discuss how the Company incorporates recognized, authoritative independent forecasts into its fuel price forecasts.

Answer:

To develop the hourly load forecast, the fuel forecast relies on both proprietary information received from third parties (Moody's Analytics economic projections and the University of Florida's Bureau of Economics & Business Research (BEBR) County population projections) and publicly available information (U.S. Bureau of Labor Statistics (BLS), U.S. Bureau of Economic Analysis (BEA), and U.S. Energy Information Administration (EIA).

To develop the commodity fuel price forecast, the fuel forecast relies on independent third-party providers of such forecasts including but not limited to Intercontinental Exchange (ICE), CoalDesk and NYMEX.

17. Please refer to the Company's January 2019 A-Schedule filing, and specifically to Schedule A-1, Page 1 of 2, Line 18, reporting Transmission and Distribution (T & D) Losses.

    a. Show the mathematical inputs and/or the calculations that were performed in order to produce the estimated dollar value of $6,540,359 for T & D Losses in this period.

b. An actual dollar value of $13,280,825 for T & D Losses was recorded for this period. Please explain the variance shown between the recorded dollar value for T & D Losses and the estimated dollar value for T & D Losses in this period.

c. Please show the mathematical inputs and/or the calculations that were performed in order to produce the estimated quantity of megawatt-hours for T & D Losses in this period.

d. An actual quantity of 339,592 megawatt-hours for T & D Losses was recorded for this period. Please explain the variance shown between the recorded quantity of megawatt-hours for T & D Losses and the estimated amount for T & D Losses in this period.

e. Schedule A-1, Page 1 of 2, Line 5, reports that the Energy Cost for Purchased Power was over 300 percent higher than estimated amounts (for dollars and megawatt-hours). Please describe the relationship, if any, between elevated purchased power costs and T & D Losses.

f. Schedule A-1, Page 1 of 2, Line 15, reports that the actual quantity of megawatt hours of Total Fuel and Net Power Transactions was about 2 percent lower than the estimated amount for the period. Please explain why the quantity of megawatt-hours for T & D Losses was recorded as over 90 percent higher than estimated amounts, despite the modest decline in the reported quantity of megawatt hours of Total Fuel and Net Power Transactions.

Answer:

a. The $6,540,359 estimated dollar amount for T&D Losses on Schedule A-1, page 1 of 2, line 18, is provided for informational purposes only. This amount is calculated as the ratio of estimated T&D Losses mWh to Total Fuel and Estimated Net Power Transactions mWh times Total Fuel and Net Power Transactions dollars:

(176,423 / 3,209,383) * $118,978,650 = $6,540,359.

b. The actual and estimated dollar amounts for T&D Losses on Schedule A-1, page 1 of 2, line 18, are provided for informational purposes only. The difference between actual T&D Losses of $13,280,825 and estimated T&D Losses of $6,540,359 is a result of the MWh variance for each line. Please see DEF's response to Interrogatory 17.d regarding the mWh variance.

c. Projected meter-level sales (retail and Company Use) for January 2019 are 3,029,065 mWh. The T&D loss factor at the time of the projection is 5.8521%. The 176,423 estimated mWh for T&D Losses for January 2019 is calculated as:

3,029,065 * 5.8521% = 177,261 – 838 = 176,423

The 838 mWh reduction is the net impact of energy efficiency programs, rooftop solar and electric vehicles.

d. The difference between actual T&D Losses mWh of 339,592 and estimated T&D Losses mWh of 176,423 on Schedule A-1, page 1 of 2, line 18, is primarily due to the allocation of mWhs between Net Unbilled, line 16, and T&D Losses, line 18. In general, for Actual mWhs, T&D Losses, line 18, is a reconciling line between Total Fuel and Net Power Transactions, line 15, and Adjusted System kWh Sales, line 19, after accounting for the impacts of Net Unbilled, line 16, and Company Use, line 17. As a result, within a single month, the allocation of mWhs between these lines can result in larger variances to projection. These variances typically resolve in the following few months.

e. While the total mWh % variance for Electric Cost for Purchased Power, line 5, was over 300 percent, the total variance for all Purchased Power, line 9, was only 13% or 38,936 mWhs. Therefore, much of the increase was offset by lower purchases from other sources. Regarding T&D Losses, it is more appropriate to view the Total Fuel and Net Power Transaction mWhs, line 15, rather than individual component lines, as the individual component lines can be offset by other sources. Please refer to DEF's response to Interrogatory 17.d regarding the variance between actual and projected T&D Losses.

f. In general, for Actual mWhs, T&D Losses, line 18, is a reconciling line between Total Fuel and Net Power Transactions, line 15, and Adjusted System kWh Sales, line 19, after accounting for the impacts of Net Unbilled, line 16, and Company Use, line 17. As a result, within a single month, the allocation of mWhs between these lines can result in larger variances to projection. This is the case for January 2019 when comparing the mWh % variance for Total Fuel and Net Power Transactions, line 15, and T&D Losses, line 18. These variances typically resolve in the following few months.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 26th day of March, 2019, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared CHRISTOPHER A. MENENDEZ, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory numbers 9 through 17 of STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 9-17) in Docket No. 20190001-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 26th day of March, 2019.

Christopher A. Menendez

MONIQUE WEST
MY COMMISSION # FF 244727
EXPIRES: June 28, 2019
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida, at Large

My Commission Expires: June 28, 2019

92

DEF's Response to Staff's Third Set of Interrogatories, No. 18

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 92
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Christopher A. Menendez (18)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 20190001-EI Dated: April 29, 2019

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S THIRD SET OF INTERROGATORIES (NO. 18)

Duke Energy Florida, LLC ("DEF") responds to the Staff of the Florida Public Service Commission's ("Staff") Third Set of Interrogatories to DEF (No. 18) as follows:

INTERROGATORIES

18. Please refer to the Company's January 2019 A-Schedule filing, and specifically to Schedule A-5, reporting on Coal inventory balances.

a. Show the mathematical inputs and/or the calculations that were performed in order to produce the Ending Inventory balance of 653,940 tons, as shown on Line 47.

b. Show the mathematical inputs and/or the calculations that were performed in order to produce a Days Supply amount of 157 days, as shown on Line 51.

c. Please explain how the Company developed its projections for a 73-day supply of Coal for this period, as shown on Line 51.

d. Please describe what actions the Company can take to reduce the current inventory of Coal.

Answer:

a. The 653,940 Ending Inventory Balance for coal on the January 2019 A-5, Line 47 is calculated as Prior Month Ending Inventory + Current Month Purchases – Current Month Burned = Current Month Ending Inventory:

Dec 2018 A-5 - Ending Inventory – Line 47	625,934
Jan 2019 A-5 – Purchases - Line 36	+157,321
Jan 2019 A-5 – Burned – Line 40	-129,315
Jan 2019 A-5 – Ending Inventory – Line 47	653,940

b. The 157 Actual Days Supply for coal on the January 2019 A-5, Line 51, is calculated as the Actual Ending Inventory Units on Line 47 / (Actual Units Burned on Line 40 / 31 days in the month):

653,940 / (129,315 / 31) = 157

Days Supply on the A-5 is calculated based on tons of coal burned in the reported month. The standard operational approach to calculating Days Supply is on a forward-looking basis by using the station's daily Full Load Burn (FLB) as the denominator. Daily FLB is the station's daily max operating capacity under normal operating conditions. Currently, the daily FLB for Crystal River is 12,747 tons of coal. If Days Supply were calculated using 12,747 tons, days on hand coal inventory for January 2018 would be approximately 51 days (653,940/12,747) versus 157.

c. The 73 estimated Days Supply for coal on the January 2019 A-5, Line 51, is calculated as the Estimated Ending Inventory Balance on Line 47 / (Estimated Units Burned on Line 40 / 30 average days in a month):

914,150 / (378,258 / 30) = 73

Please also see the response to ROG 18-B, as this calculation also uses the coal burned from the current reported month.

d. As explained in DEF's response to Staff Interrogatory 18-B above, DEF's coal inventory levels represent a Day Supply of approximately 51 days. DEF continually evaluates fuel inventory levels to ensure sufficient fuel to meet our customer's needs, while maintaining the ability to mitigate potential disruptions. DEF believes that the current coal inventory levels meet these needs; however, DEF continually evaluates coal inventory levels at Crystal River. Potential options the Company can take to possibly slow down the accumulation of coal or reduce inventory volumes include:- 1) Working with suppliers to defer deliveries; 2) Exercising contracted volume flexibility to reduce contractual commitments; 3) Utilizing open coal position flexibility and adjust quarterly RFP spot purchases to reduce inventory through economic dispatch; 4) Utilizing excess terminal storage; and/or 5) Selling coal via market sales or contractual buyouts.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 29th day of April, 2019, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared CHRISTOPHER A. MENENDEZ, who is personally known to me, and has acknowledged before me that he provided the answers to interrogatory number 18 of STAFF'S THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NO. 18) in Docket No. 20190001-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 29th day of April, 2019.

Christopher A. Menendez

MONIQUE WEST
MY COMMISSION # FF 244727
EXPIRES: June 28, 2019
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida, at Large

My Commission Expires: June 28, 2019

93

FPUC's Response to Staff's First Set of Interrogatories, No. 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 93
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Mark Cutshaw (1)

Interrogatory No. 1a

INTERROGATORIES

For the purpose of the interrogatory number 1, please refer to FPUC's December 2018 A Schedule filing, and the specific schedule and line number identified below.

1. Schedule A2, Line 6a, on Page 1 of 4, reports the Period To Date amount of $473,856 was charged to customers for Special Meetings – Fuel Market Issue for the period January-December, 2018.

   A. Please explain the reason(s) for the variance between the year-to-date actual costs that were recorded, and the amount the Company projected to spend for the period January-December, 2018, which was $221,000.

Company Response:

During the early part of 2018, the Company began the process of evaluating purchased power supply options for its Northwest Florida division for which the current agreement will expire in December 2019. The evaluating process included an identification of potential suppliers, resource mix, transmission options and the overall optimization of the power supplies for January 2020 and beyond. Also included in this process are the review of an additional CHP (Combined Heat and Power) facility on Amelia Island as well as how the future power supply could be used to optimize this additional resource. For this purpose, the Company utilized the services of energy consultants, Pierpont and McClelland to a greater degree in 2018 than during the 2017 time period.

Respondent: *Mark Cutshaw*

20190001.EI Staff Hearing Exhibits 00127

Interrogatory No. 1b

B. For the Company's Northeast Division, did any power supply arrangements expire in 2018? Describe the Company's efforts in securing power supply arrangements to serve the Northeast Division in 2019 and beyond. State in your response the expiration date(s) of all current power supply arrangements to serve the Northeast Division.

Company Response:

There were no changes in the Company's Northeast Florida power supply arrangement during 2018 and there were no efforts to find additional power supply for this area. Currently, there are agreements with Florida Power and Light (expiring December 2024) and with Eight Flags Energy, LLC. (expiring June 2036).

Respondent: *Mark Cutshaw*

Interrogatory No. 1c

C. For the Company's Northwest Division, did any power supply arrangements expire in 2018? Describe the Company's efforts in securing power supply arrangements to serve the Northwest Division in 2019 and beyond. State in your response the expiration date(s) of all current power supply arrangements to serve the Northwest Division.

Company Response:

There were no changes in the Northwest Florida power supply arrangement during 2018. Currently, there is an agreement with Southern Co./Gulf Power Company that is set to expire in December 2019. During 2018 and continuing into 2019, activities to investigate future power supply and transmission services occurred in order to identify power supply prior to the end of 2019.

Respondent: *Mark Cutshaw*

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF NASSAU)

I hereby certify that on this 12th day of March, 2019, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared P. Mark Cutshaw, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 1 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITES COMPANY (NO. 1) in Docket No(s). 20190001-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 12 day of March, 2019.

Lynn M. McNeill
NOTARY PUBLIC
STATE OF FLORIDA
Comm# GG023493
Expires 8/22/2020

Lynn M'Neill
Notary Public
State of Florida, at Large

My Commission Expires:
8/22/2020

94

FPUC's Response to Staff's Second Set of Interrogatories, Nos. 2-10

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 94
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Curtis D. Young (2-10)

Interrogatory No. 2

INTERROGATORIES

2. Please describe the steps the Company undertook to prepare the fuel price forecast the Company prepared to support its 2019 projections, as filed on August 24, 2018, in Docket No. 20180001. Discuss in your response when these steps were started and when these steps were concluded, and how the timeline for preparing this forecast compared to the timeline for preparing the similar forecasts for 2017 or 2018.

Company Response:

The Company begins the process of gathering forecasted data in July. The Kwh sales and purchases data is derived from the company's budget and entered into its projection schedules. Another component of the Company's fuel price forecast are the cost factors charged by its power suppliers. These data are gathered from the terms within the respective purchase power agreements and contractual obligations with the Company's suppliers. The Company also includes in its fuel price forecast the estimates of other fuel–related costs, such as consultant and legal costs associated with pursuing and negotiating fuel costs savings to be passed on to FPUC's customers. All the aforementioned data is then entered into rate calculating worksheets within the E-Schedules in older to compute the forecasted fuel prices. The steps are concluded to meet the same timeline as the Projected Fuel filing due dates. The Company followed the same steps and timeline as it did for the similar forecasts for 2017 and 2018.

Respondent: Curtis D. Young

Interrogatory No. 3

3. How often are fuel price forecasts prepared? Discuss in your response what triggers, or market observations would prompt the Company to update its fuel price forecast.

Company Response:

As noted in the Company's response to # 2, its fuel price forecasts are triggered solely by the timing of its annual Fuel Projection filings.

Respondent: Curtis D. Young

Interrogatory No. 4

4. If known, identify the date the next fuel price forecast is scheduled to be prepared.

Company Response:

See Response to # 2.

Respondent: Curtis D. Young

Interrogatory No. 5

5. Please identify the forecasting sources that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

Company Response:

See Response to # 2.

Respondent: Curtis D. Young

Interrogatory No. 6

6. Were any of the sources identified in the response to Interrogatory number 5 new or different than the sources used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

Company Response:

No, the forecasting sources used for preparing the Company's 2019 Fuel Projections were not different than the sources used to prepare forecasts for 2017 and 2018, except to the extent that the Company has entered into new Purchased Power Agreements, which now serve as the Company's forecasting sources.

Respondent: Curtis D. Young

Interrogatory No. 7

7. Please identify the forecasting assumptions that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

Company Response:

The Company's fuel forecasts were for the most part based on known data, with the exception of projected Kwh sales being obtained from the Company's budget process. The forecasting assumptions used for projected kwh sales were an anticipated customer growth percentage and a 3-year average usage per customer.

Respondent: Curtis D. Young

Interrogatory No. 8

8. Were any of the assumptions identified in the response to Interrogatory number 7 new or different than the assumptions used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

Company Response:

The Company used the same assumptions as identified in previous response number 7 with only minimal differences in the anticipated customer growth percentages and the respective 3-year average usage per customer for relative years.

Respondent: Curtis D. Young

20190001.EI Staff Hearing Exhibits 00138

Interrogatory No. 9

9. Discuss how the Company incorporates recognized, authoritative independent forecasts into its fuel price forecasts.

Company Response:

The Company does not typically involve or incorporate recognized, authoritative independent forecasts into its fuel price forecasts.

Respondent: Curtis D. Young

Interrogatory No. 10(a)

10. Please refer to the Company's January 2019 A-Schedule filing, and specifically to Schedule A-1, Line 23, reporting Transmission and Distribution (T & D) Losses.

a. Please show the mathematical inputs and/or the calculations that were performed in order to produce the dollar values for T & D Losses in this period.

Company Response:

Please refer to attached Exhibit A.

Respondent: Curtis D. Young

Interrogatory No. 10(b)

b. An actual dollar value of $283,643 for T & D Losses was recorded in Column A for this period. Please explain the variance shown between the recorded dollar value for T & D Losses and the estimated dollar value for T & D Losses in this period.

Company Response:

The variance between the recorded dollar value for T & D Losses and the estimated dollar value for T & D Losses is primarily due to fuel costs being lower in this period than projected. The supporting calculation is illustrated in attached Exhibit A.

Respondent: Curtis D. Young

Interrogatory No. 10(c)

c. An actual dollar value of $283,643 for T & D Losses was recorded in Column A for this period. Please explain the variance shown between the recorded dollar value for T & D Losses and the estimated dollar value for T & D Losses in this period.

Company Response:

Same question and response as 10 b above.

Respondent: Curtis D. Young

20190001.EI Staff Hearing Exhibits 00142

Interrogatory No. 10(d)

d. An actual quantity of 3,371 megawatt-hours for T & D Losses was recorded for this period. Please explain the variance shown between the recorded quantity and the estimated quantity of kilowatt-hours for T & D Losses in this period.

Company Response:

Please refer to attached Exhibit A.

Respondent: Curtis D. Young

Interrogatory No. 10(e)

e. Schedule A-1, Line 12, reports that the Total Cost of Purchased Power was over 5 percent lower than estimated amounts for dollars. Please explain why T & D Losses (shown on Line 23) are higher by a larger percentage for dollars, than the entries for Line 12.

Company Response:

The T &D Losses (shown on Line 23) are lower than estimated amounts by a comparative percentage for dollars.

Respondent: Curtis D. Young

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 1st day of April, 2019, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Curtis D. Young, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 2 - 10 from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITES COMPANY (NOS. 2-10) in Docket No(s). 20190001-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 1st day of April, 2019.

DINA BELLECHASSE
MY COMMISSION # FF 912362
EXPIRES: December 13, 2019
Bonded Thru Notary Public Underwriters

Dina Bellechasse
Notary Public
State of Florida, at Large

My Commission Expires:
12/13/2019

Florida Public Utilities Company
Response to Staff's Second Set of Interrogatories (No. 2-10)
Docket No. 20190001-EI
EXHIBIT A.

Response to Question 10 a.

(1)	Total Fuel and Net Power Transactions	$	4,727,790
(2)	Total Megawatt Hours Puchased		56,188
(3)	Cost per MWH {(1) ÷ (2)}	$	84.1423
(4)	T & D Losses (MWH) Estimated at 6% {(2) × 6%}		3,371
(5)	T & D Losses {(3) × (4)}	$	283,643

Response to Question 10 b, 10 c and 10 d.

		Actual		Estimated
(1)	Total Fuel and Net Power Transactions	$ 4,727,790	$	5,078,689
(2)	Total Megawatt Hours Puchased	56,188		58,095
(3)	Cost per MWH {(1) ÷ (2)}	$ 84.1423	$	87.4204
(4)	T & D Losses (MWH) Estimated a 6% {(2) × 6%}	3,371		3,486
(5)	T & D Losses {(3) × (4)}	$ 283,643	$	304,746

Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: JANUARY 2019

SCHEDULE A1
PAGE 1 OF 2

		DOLLARS				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	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	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)			0	0.0%								
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)	1,781,002	1,798,547	(17,545)	-1.0%	40,750	40,695	55	0.1%	4.37056	4.41955	(0.04899)	-1.1%
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)	1,821,789	2,064,673	(242,884)	-11.8%	40,750	40,695	55	0.1%	4.47065	5.07350	(0.60285)	-11.9%
11	Energy Payments to Qualifying Facilities (A8a)	1,321,673	1,333,624	(11,951)	-0.9%	15,438	17,400	(1,962)	-11.3%	8.56112	7.66451	0.89661	11.7%
12	TOTAL COST OF PURCHASED POWER	4,924,464	5,196,844	(272,380)	-5.2%	56,188	58,095	(1,907)	-3.3%	8.76425	8.94539	(0.18114)	-2.0%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					56,188	58,095	(1,907)	-3.3%				
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)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	196,674	118,155	78,519	-18.9%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	4,727,790	5,078,689	(350,899)	-6.9%	56,188	58,095	(1,907)	-3.3%	8.41422	8.74201	(0.32779)	-3.8%
21	Net Unbilled Sales (A4)	280,016 *	(180,550) *	440,566	-274.4%	3,328	(1,837)	5,164	-281.2%	0.56617	(0.28465)	0.85082	-298.9%
22	Company Use (A4)	2,625 *	3,738 *	(1,113)	-29.8%	31	43	(12)	-27.0%	0.00531	0.00663	(0.00132)	-19.9%
23	T & D Losses (A4)	283,643 *	304,748 *	(21,103)	-6.9%	3,371	3,486	(115)	-3.3%	0.57350	0.54030	0.03320	6.1%
24	SYSTEM KWH SALES	4,727,790	5,078,689	(350,899)	-6.9%	49,458	56,403	(6,945)	-12.3%	9.55920	9.00429	0.55491	6.2%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	4,727,790	5,078,689	(350,899)	-6.9%	49,458	56,403	(6,945)	-12.3%	9.55920	9.00429	0.55491	6.2%
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	4,727,790	5,078,689	(350,899)	-6.9%	49,458	56,403	(6,945)	-12.3%	9.55920	9.00429	0.55491	6.2%
28	GPIF**												
29	TRUE-UP**	329,814	329,814	0	0.0%	49,458	56,403	(6,945)	-12.3%	0.66688	0.58475	0.08211	14.0%
30	TOTAL JURISDICTIONAL FUEL COST (Excluding GSLD Apportionment)	5,057,604	5,408,503	(350,899)	-6.5%	49,458	56,403	(6,945)	-12.3%	10.22608	9.58903	0.63703	6.6%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									10.39060	9.74332	0.64728	6.6%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									10.391	9.743	0.648	6.7%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

20190001.EI Staff Hearing Exhibits 00147

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Gulf's Response to Staff's First Set of Interrogatories, Nos. 1-7

CONFIDENTIAL DN. 03157-2019

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 95
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Shane Boyett (1-7)

1. For each Request for Proposal (RFP) for coal issued in 2018 by or on behalf of Gulf, list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

ANSWER:

OCTOBER 2, 2018 LONG-TERM RFP

A solicitation (RFP) was issued on October 2, 2018, on behalf of Southern Company, soliciting bids from all suppliers contained in Southern Company's Internet Bid System (CIBS), which includes approved suppliers listed on the Gulf Power Company Bid List. Regarding the October 2, 2018, solicitation, purchases of bituminous coal were to be made for Plant Crist. The solicitation requested bids for a term beginning January 1, 2019, through December 31, 2021 (three years).

In response to this RFP, eighteen (18) bids were received from nine (9) different coal suppliers. The bids received were from the Central Appalachian, Northern Appalachian, Illinois Basin, Colorado and Colombian coal supply regions.

Table 1 (2019 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered($/MMBtu)
1	FORESIGHT	[redacted]	[redacted]	RAIL	[redacted]
8	PEABODY			RAIL	
9	SUNRISE			RAIL	
10	SUNRISE			RAIL	
11	WHITE STALLION			RAIL	
3	ALLIANCE			RAIL	
4	ALLIANCE			RAIL	
14	WHITE STALLION			BARGE	
13	WHITE STALLION			BARGE	
6	PEABODY			RAIL	
12	WHITE STALLION			RAIL	
2	CONTURA			RAIL	
7	PEABODY			RAIL	
17	ARCH			RAIL	
18	SOUTHLAND RESOURCES			TRUCK	
16	ARCH			RAIL	
5	PEABODY			RAIL	
15	GLENCORE			BARGE	

MAY 29, 2018 LONG-TERM RFP

A solicitation (RFP) was issued on May 29, 2018, on behalf of Southern Company, soliciting bids from all suppliers contained in Southern Company's Internet Bid System (CIBS), which includes approved suppliers listed on the Gulf Power Company Bid List.
Regarding the May 29, 2018, solicitation, purchases of sub-bituminous coal were to be made for Plant Daniel. The solicitation requested bids for a term beginning January 1, 2019, through December 31, 2022 (four years).

In response to this RFP, thirteen (13) bids were received from five (5) different coal suppliers. The bids received were from the Powder River Basin coal supply region. Below is a listing of the bids that were received:

Table 2 (2019 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered($MMBtu)
13	BLACKJEWEL			RAIL	
8	PEABODY			RAIL	
12	BUCKSKIN			RAIL	
7	PEABODY			RAIL	
11	ARCH COAL			RAIL	
10	ARCH COAL			RAIL	
6	PEABODY			RAIL	
9	ARCH COAL			RAIL	
2	CLOUD PEAK			RAIL	
5	PEABODY			RAIL	
1	CLOUD PEAK			RAIL	
4	PEABODY			RAIL	
3	CLOUD PEAK			RAIL	

AUGUST 30, 2018 SHORT-TERM RFP

A solicitation (RFP) was issued on August 30, 2018, on behalf of Southern Company, soliciting bids from all suppliers contained in Southern Company's Internet Bid System (CIBS), which includes approved suppliers listed on the Gulf Power Company Bid List.
Regarding the August 30, 2018 solicitation, purchases of bituminous coal were to be made for Plant Daniel. The solicitation requested bids for a term beginning October 1, 2018, through March 31, 2019.

In response to this RFP, six (6) bids were received from five (5) different coal suppliers. The bids received were from the Central Appalachian, Northern Appalachian, Illinois Basin, Colorado and Colombian coal supply regions. Below is a listing of the bids that were received:

Table 3 (2018 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
3	WISE ENERGY GROUP	[redacted]	[redacted]	RAIL	[redacted]
6	WHITE STALLION ENERGY, LLC	[redacted]	[redacted]	RAIL	[redacted]
1	MURRAY ENERGY CORP	[redacted]	[redacted]	RAIL	[redacted]
5	WHITE STALLION ENERGY, LLC	[redacted]	[redacted]	RAIL	[redacted]
4	PEERLESS MINERALS, LLC	[redacted]	[redacted]	RAIL	[redacted]
2	ARCH COAL INC.	[redacted]	[redacted]	RAIL	[redacted]

OCTOBER 2, 2018 LONG-TERM RFP

A solicitation (RFP) was issued on October 2, 2018, on behalf of Southern Company, soliciting bids from all suppliers contained in Southern Company's Internet Bid System (CIBS), which includes approved suppliers listed on the Gulf Power Company Bid List. Regarding the October 2, 2018, solicitation, purchases of bituminous coal were to be made for Plant Daniel. The solicitation requested bids for a term beginning January 1, 2019 through December 31, 2021 (three years).

In response to this RFP, eighteen (18) bids were received from nine (9) different coal suppliers. The bids received were from the Central Appalachian, Northern Appalachian, Illinois Basin, Colorado and Colombian coal supply regions. Below is a listing of the bids that were received:

Table 4 (2019 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
1	FORESIGHT	[redacted]	[redacted]	RAIL	[redacted]
8	PEABODY			RAIL	
9	SUNRISE COAL			RAIL	
10	SUNRISE COAL			RAIL	
3	ALLIANCE			RAIL	
4	ALLIANCE			RAIL	
11	WHITE STALLION			RAIL	
14	WHITE STALLION			RAIL	
13	WHITE STALLION			RAIL	
6	PEABODY			RAIL	
12	WHITE STALLION			RAIL	
7	PEABODY			RAIL	
17	ARCH			RAIL	
16	ARCH			RAIL	
5	PEABODY			RAIL	
18	SOUTHLAND RESOURCES			RAIL	
15	GLENCORE			RAIL	
1	FORESIGHT			RAIL	

Table 5 (2020 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
1	FORESIGHT	[redacted]	[redacted]	RAIL	[redacted]
10	SUNRISE COAL			RAIL	
8	PEABODY			RAIL	
9	SUNRISE COAL			RAIL	
3	ALLIANCE			RAIL	
11	WHITE STALLION			RAIL	
14	WHITE STALLION			RAIL	
12	WHITE STALLION			RAIL	
6	PEABODY			RAIL	
13	WHITE STALLION			RAIL	
2	CONTURA			RAIL	
7	PEABODY			RAIL	
17	ARCH			RAIL	
5	PEABODY			RAIL	

FEBRUARY 8, 2018 SHORT-TERM RFP

A solicitation (RFP) was issued on February 8, 2018, on behalf of Southern Company, soliciting bids from all suppliers contained in Southern Company's Internet Bid System (CIBS), which includes approved suppliers listed on the Gulf Power Company Bid List. Regarding the February 8, 2018, solicitation, purchases of sub-bituminous coal were to be made for Plant Scherer. The solicitation requested bids for a term beginning April 1, 2018, through June 30, 2018 (three months).

In response to this RFP, eleven (11) bids were received from five (5) different coal suppliers. The bids received were from the Powder River Basin coal supply region. Below is a listing of the bids that were received:

Table 6 (2018 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
5	BLACKJEWEL EAGLE BUTTE	[redacted]	[redacted]	RAIL	[redacted]
1	BUCKSKIN	[redacted]	[redacted]	RAIL	[redacted]
11	PEABODY RAWHIDE	[redacted]	[redacted]	RAIL	[redacted]
9	PEABODY CABALLO	[redacted]	[redacted]	RAIL	[redacted]
2	CLOUD PEAK CORDERO ROJO	[redacted]	[redacted]	RAIL	[redacted]
10	PEABODY NARM NORTH	[redacted]	[redacted]	RAIL	[redacted]
6	BLACKJEWEL BELLE AYR	[redacted]	[redacted]	RAIL	[redacted]
4	ARCH BLACK THUNDER	[redacted]	[redacted]	RAIL	[redacted]
3	CLOUD PEAK ANTELOPE	[redacted]	[redacted]	RAIL	[redacted]
7	PEABODY NARM	[redacted]	[redacted]	RAIL	[redacted]
8	PEABODY NARM	[redacted]	[redacted]	RAIL	[redacted]

MAY 29, 2018 SHORT-TERM RFP

A solicitation (RFP) was issued on May 29, 2018, on behalf of Southern Company, soliciting bids from all suppliers contained in Southern Company's Internet Bid System (CIBS), which includes approved suppliers listed on the Gulf Power Company Bid List.

Regarding the May 29, 2018, solicitation, purchases of sub-bituminous coal were to be made for Plant Scherer. The solicitation requested bids for a term beginning July 1, 2018 through September 30, 2018 (three months).

In response to this RFP, twelve (12) bids were received from five (5) different coal suppliers. The bids received were from the Powder River Basin coal supply region. Below is a listing of the bids that were received:

Table 7 (2018 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
11	BLACKJEWEL EAGLE BUTTE	[redacted]	[redacted]	RAIL	[redacted]
6	BUCKSKIN			RAIL	
5	PEABODY RAWHIDE			RAIL	
3	PEABODY CABALLO			RAIL	
8	CLOUD PEAK CORDERO ROJO			RAIL	
10	ARCH COAL CREEK			RAIL	
4	PEABODY NARM NORTH			RAIL	
7	CLOUD PEAK ANTELOPE			RAIL	
9	ARCH BLACK THUNDER			RAIL	
12	BLACKJEWEL BELLE AYR			RAIL	
1	PEABODY NARM			RAIL	
2	PEABODY NARM			RAIL	

MAY 29, 2018 LONG-TERM RFP

A solicitation (RFP) was issued on May 29, 2018, on behalf of Southern Company, soliciting bids from all suppliers contained in Southern Company's Internet Bid System (CIBS), which includes approved suppliers listed on the Gulf Power Company Bid List.

Regarding the May 29, 2018, solicitation, purchases of sub-bituminous coal were to be made for Plant Scherer. The solicitation requested bids for a term beginning January 1, 2019, through December 31, 2022 (four years).

In response to this RFP, thirteen (13) bids were received from five (5) different coal suppliers. The bids received were from the Powder River Basin coal supply region. Below is a listing of the bids that were received:

Table 8 (2019 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
13	BLACKJEWEL EAGLE BUTTE	[redacted]	[redacted]	RAIL	[redacted]
8	PEABODY RAWHIDE			RAIL	
7	PEABODY CABALLO			RAIL	
12	BUCKSKIN			RAIL	
11	ARCH COAL CREEK (BUY > 2M)			RAIL	
6	PEABODY NARM NORTH			RAIL	
2	CLOUD PEAK CORDERO ROJO			RAIL	
10	ARCH COAL CREEK			RAIL	
5	PEABODY NARM			RAIL	
9	ARCH BLACK THUNDER			RAIL	
1	CLOUD PEAK ANTELOPE			RAIL	
4	PEABODY NARM			RAIL	
3	CLOUD PEAK YOUNGS CREEK			RAIL	

Table 9 (2020 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
3	PEABODY RAWHIDE	[redacted]	[redacted]	RAIL	[redacted]
8	BLACKJEWEL EAGLE BUTTE			RAIL	
15	PEABODY CABALLO			RAIL	
7	BUCKSKIN			RAIL	
14	PEABODY NARM NORTH			RAIL	
6	CLOUD PEAK CORDERO ROJO			RAIL	
2	ARCH COAL CREEK (BUY > 2M)			RAIL	
11	ARCH COAL CREEK			RAIL	
10	PEABODY NARM			RAIL	
5	ARCH BLACK THUNDER			RAIL	
1	CLOUD PEAK ANTELOPE			RAIL	
4	PEABODY NARM			RAIL	

Table 10 (2021 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
8	PEABODY RAWHIDE	[redacted]	[redacted]	RAIL	[redacted]
15	BLACKJEWEL EAGLE BUTTE			RAIL	
7	PEABODY CABALLO			RAIL	
2	CLOUD PEAK CORDERO ROJO			RAIL	
6	PEABODY NARM NORTH			RAIL	
14	BUCKSKIN			RAIL	
5	PEABODY NARM			RAIL	
11	ARCH COAL CREEK (BUY > 2M)			RAIL	
10	ARCH COAL CREEK			RAIL	
9	ARCH BLACK THUNDER			RAIL	
4	PEABODY NARM			RAIL	
1	CLOUD PEAK ANTELOPE			RAIL	

Table 11 (2022 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
8	PEABODY RAWHIDE	[redacted]	[redacted]	RAIL	[redacted]
15	BLACKJEWEL EAGLE BUTTE			RAIL	
7	PEABODY CABALLO			RAIL	
2	CLOUD PEAK CORDERO ROJO			RAIL	
6	PEABODY NARM NORTH			RAIL	
14	BUCKSKIN			RAIL	
5	PEABODY NARM			RAIL	
9	ARCH BLACK THUNDER			RAIL	
11	ARCH COAL CREEK (BUY > 2M)			RAIL	
4	PEABODY NARM			RAIL	
10	ARCH COAL CREEK			RAIL	
1	CLOUD PEAK ANTELOPE			RAIL	

AUGUST 6, 2018 SHORT-TERM RFP

A solicitation (RFP) was issued on August 6, 2018, on behalf of Southern Company, soliciting bids from all suppliers contained in Southern Company's Internet Bid System (CIBS), which includes approved suppliers listed on the Gulf Power Company Bid List. Regarding the August 6, 2018, solicitation, purchases of sub-bituminous coal were to be made for Plant Scherer. The solicitation requested bids for a term beginning October 1, 2018, through December 31, 2018 (three months).

In response to this RFP, ten (10) bids were received from five (5) different coal suppliers. The bids received were from the Powder River Basin coal supply region. Below is a listing of the bids that were received:

Table 12 (2018 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
1	BUCKSKIN			RAIL	
2	BLACKJEWEL EAGLE BUTTE			RAIL	
9	PEABODY CABALLO			RAIL	
4	CLOUD PEAK CORDERO ROJO			RAIL	
3	CLOUD PEAK ANTELOPE			RAIL	
10	PEABODY NARM NORTH			RAIL	
6	ARCH BLACK THUNDER			RAIL	
5	ARCH BLACK THUNDER			RAIL	
7	PEABODY NARM NORTH			RAIL	
8	PEABODY NARM			RAIL	

AUGUST 31, 2018 LONG-TERM RFP

A solicitation (RFP) was issued on August 31, 2018, on behalf of Southern Company, soliciting bids from all suppliers contained in Southern Company's Internet Bid System (CIBS), which includes approved suppliers listed on the Gulf Power Company Bid List. Regarding the August 31, 2018, solicitation, purchases of sub-bituminous coal were to be made for Plant Scherer. The solicitation requested bids for a term beginning January 1, 2019, through December 31, 2022 (four years).

In response to this RFP, twelve (12) bids were received from five (5) different coal suppliers. The bids received were from the Powder River Basin coal supply region. Below is a listing of the bids that were received:

Table 13 (2019 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
12	BLACKJEWEL	[redacted]	[redacted]	RAIL	[redacted]
5	PEABODY			RAIL	
11	BUCKSKIN			RAIL	
4	PEABODY			RAIL	
9	ARCH			RAIL	
3	PEABODY			RAIL	
7	CLOUD PEAK			RAIL	
2	PEABODY			RAIL	
6	CLOUD PEAK			RAIL	
1	PEABODY			RAIL	
8	CLOUD PEAK			RAIL	

*Bid No 10 was not applicable to plant Scherer, thus it was not included in the lineup

Table 14 (2020 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
5	PEABODY	[redacted]	[redacted]	RAIL	[redacted]
12	BLACKJEWEL			RAIL	
4	PEABODY			RAIL	
11	BUCKSKIN			RAIL	
3	PEABODY			RAIL	
7	CLOUD PEAK			RAIL	
9	ARCH			RAIL	
2	PEABODY			RAIL	
6	CLOUD PEAK			RAIL	
1	PEABODY			RAIL	

Table 15 (2021 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
5	PEABODY	[redacted]	[redacted]	RAIL	[redacted]
12	BLACKJEWEL			RAIL	
4	PEABODY			RAIL	
3	PEABODY			RAIL	
7	CLOUD PEAK			RAIL	
11	BUCKSKIN			RAIL	
9	ARCH			RAIL	
2	PEABODY			RAIL	
6	CLOUD PEAK			RAIL	
1	PEABODY			RAIL	

Table 16 (2022 Bids):

A	B	C	D	E	F
Bid	Supplier	Tons	Btu/lb.	Transport	Delivered ($MMBtu)
5	PEABODY	[redacted]	[redacted]	RAIL	[redacted]
12	BLACKJEWEL			RAIL	
4	PEABODY			RAIL	
3	PEABODY			RAIL	
7	CLOUD PEAK			RAIL	
11	BUCKSKIN			RAIL	
9	ARCH			RAIL	
2	PEABODY			RAIL	
1	PEABODY			RAIL	
6	CLOUD PEAK			RAIL	

2. Please describe the action taken for each bid identified in response to Interrogatory No. 1. Include in your response an explanation of the evaluation process and how successful proposals were selected.

ANSWER:

OCTOBER 2, 2018 LONG-TERM RFP

In 2018, Gulf Power Company had a requirements contract in place with Alliance Coal LLC. This resulted in Gulf Power Company having no uncommitted need during this time-period. This RFP was for coal to replace the requirements contract in 2019.

To replace the Alliance requirements contract in 2019, the RFP solicited bids from all approved suppliers to Southern Company. Gulf elected to use a portion of the offers from this RFP to set Alliance's 2019 price. In addition, Gulf obtained emailed offers from three Colombian sources to establish a blend price that could be used for the market review. Glencore and Drummond submitted offers. CMC elected not to bid. Only Drummond's Interocean offer was competitive at [redacted] The RFP requested bids to supply up to 3.0M tons of coal for the period January 1, 2019, through December 31, 2021, to support Southern Company's bituminous projected coal burn and inventory requirements. The bid close date was October 19, 2018. In response to the solicitation, eighteen (18) offers were received from nine (9) different coal suppliers. Offers were received from the Central Appalachian, Southern Appalachian, Northern Appalachian, Illinois Basin, Western Bituminous and Colombian coal supply regions.

An evaluation to derive a delivered $/MMBtu least cost line-up was performed using applicable transportation rates and emission allowance values. After reviewing the offers, a competitive buy line was established utilizing the most economical offers including their respective optionality value. The least cost offer received from these bids came from Foresight Coal Sales LLC's Sugar Camp Mine. This coal delivered for [redacted] however, it was determined that this coal could not be burned by itself and needed to be blended with a lower sulfur product. On December 6, 2018 Interocean Coal Sales, LLC submitted an unsolicited offer to Gulf for approximately 640,000 tons to be delivered in 2019. This coal delivered for [redacted] After canvasing the Central Appalachian (CAPP), Colorado and the remaining Colombian suppliers via phone and emails, it was determined that no other low sulfur source could be obtained to complete the blend ratios in compliance with Plant Crist SO_2 limitation of 2.0 lbs. SO_2/MMBtu. As a result, Gulf purchased Foresight's Sugar Camp coal and Interocean's Colombian coal to utilize in 2019 at a blended delivered price of [redacted]

MAY 29, 2018 LONG-TERM RFP

Regarding the May 29, 2018, sub-bituminous solicitation, a review of Plant Daniel's inventory plan and burn projections indicated a need to purchase a sub-bituminous coal for delivery in 2019. The applicable bids received were evaluated on a fully delivered $/MMBtu basis, including the value of sulfur. In support of the evaluation process, transportation rates and SO2 allowance values were provided and included as part of the analysis. Other inputs to the evaluation included railcar lease and maintenance and dust suppression costs.

An evaluation to derive a delivered $/MMBtu least cost line-up was performed using applicable transportation rates and emission allowance values. After reviewing the offers, a competitive buy line was established utilizing the most economical offers. The least cost offer received from these bids came from Blackjewel's Eagle Butte mine delivering at [redacted] However, the Btu of this coal does not meet the minimum required of 8,800 Btu at Plant Daniel. The second least-cost offer was Peabody Energy at [redacted] However, this coal also did not meet the quality specifications required by Plant Daniel. The first offer meeting the quality requirements of Plant Daniel was Arch Coal's Black Thunder Mine delivering at [redacted] This coal was offered as a balance of plant requirement deal for 2019, meaning Arch's Black Thunder Mine would supply the amount of sub-bituminous coal required by Plant Daniel with a minimum commitment of 200,000 tons. The delivery period for the requirements deal would begin January 2019 through December 2019.

AUGUST 30, 2018 SHORT-TERM RFP

Regarding the August 30, 2018 bituminous solicitation, a review of Plant Daniel's inventory plan and burn projections for September through December 2018 indicated a need to purchase a low sulfur bituminous coal for delivery in September through December 2018. The applicable bids received were evaluated on a fully delivered $/MMBtu basis, including the value of sulfur. In support of the evaluation process, transportation rates and SO2 allowance values were provided and included as part of the analysis. Other inputs to the evaluation included railcar lease and maintenance.

An evaluation to derive a delivered $/MMBtu least cost line-up was performed using applicable transportation rates and emission allowance values. After reviewing the offers, a competitive buy line was established utilizing the most economical offers. The least cost offer received from these bids came from Wise Energy Group at [redacted] However, the sulfur level of this coal exceeded the plant limitation. The next four offers were also rejected because their sulfur limits exceeded the sulfur limit at the plant. The first offer meeting the quality requirements of Plant Daniel was Arch Coal's West Elk mine delivering at [redacted] It was determined to procure approximately 84,000 tons for delivery September through December 2018.

OCTOBER 2, 2018 LONG-TERM RFP

Regarding the October 2, 2018, bituminous solicitation, a review of Plant Daniel's inventory plan and burn projections for January 2019 through December 2020 indicated a need to purchase a low sulfur bituminous coal for delivery in 2019 through 2020. The applicable bids received were evaluated on a fully delivered $/MMBtu basis, including the value of sulfur. In support of the evaluation process, transportation rates and SO2 allowance values were provided and included as part of the analysis. Other inputs to the evaluation included railcar lease and maintenance.

An evaluation to derive a delivered $/MMBtu least cost line-up was performed using applicable transportation rates and emission allowance values. After reviewing the offers, a competitive buy line was established utilizing the most economical offers. For the 2019 delivery period, the least cost offer received from these bids came from Foresight a [redacted] However, the sulfur level of this coal exceeded the plant limitation. The next several offers were also rejected because their sulfur limits exceeded the sulfur limit at the plant.

The first offer meeting the quality requirements of Plant Daniel was Arch Coal's West Elk mine delivering at [redacted] Due to the volume required by Daniel for 2019 purchase, the offer delivering at [redacted] was selected. It was determined to procure approximately 200,000 tons of Arch's West Elk coal for delivery in 2019. It was determined to procure approximately 75,000 tons of Peabody's Twentymile coal delivering a [redacted] or delivery in 2019 to meet the need at the time of the solicitation. In 2020, the first offer meeting the sulfur limit was Arch's West Elk coal delivering at [redacted] It was determined to purchase 100,000 tons of Arch's West Elk coal for delivery January through December 2020.

FEBRUARY 8, 2018 SHORT-TERM RFP

Regarding the February 8, 2018 sub-bituminous solicitation, a review of Plant Scherer's inventory plan and burn projections for April through June 2018 indicated a need to purchase a sub-bituminous coal for delivery in April through June 2018. The applicable bids received were evaluated on a fully delivered $/MMBtu basis, including the value of sulfur. In support of the evaluation process, transportation rates and SO2 allowance values were provided and included as part of the analysis. Other inputs to the evaluation included railcar lease and maintenance and dust suppression costs.

An evaluation to derive a delivered $/MMBtu least cost line-up was performed using applicable transportation rates and emission allowance values. After reviewing the offers, a competitive buy line was established utilizing the most economical offers. The least cost offer received from these bids came from Blackjewel's Eagle Butte mine delivering at [redacted] The bid from Blackjewel was dismissed due to recent quality issues with shipments. The next least cost offer was from Kiewit Mining Group's Buckskin Mine delivering at [redacted] It was determined to procure approximately 245,000 tons

from Buckskin for delivery April through June 2018.

MAY 29, 2018 SHORT-TERM RFP

Regarding the May 29, 2018 sub-bituminous solicitation, a review of Plant Scherer's inventory plan and burn projections for July through September 2018 indicated a need to purchase a sub-bituminous coal for delivery in July through September 2018. The applicable bids received were evaluated on a fully delivered $/MMBtu basis, including the value of sulfur. In support of the evaluation process, transportation rates and SO2 allowance values were provided and included as part of the analysis. Other inputs to the evaluation included railcar lease and maintenance and dust suppression costs.
An evaluation to derive a delivered $/MMBtu least cost line-up was performed using applicable transportation rates and emission allowance values. After reviewing the offers, a competitive buy line was established utilizing the most economical offers. The least cost offer received from these bids came from Blackjewel's Eagle Butte mine delivering at [redacted] The bid from Blackjewel was dismissed due to recent quality issues with shipments. The next least cost offer was from Kiewit Mining Group's Buckskin Mine delivering at [redacted] It was determined to procure approximately 200,000 tons from Buckskin for delivery July through September 2018.

MAY 29, 2018 LONG-TERM RFP

Regarding the May 29, 2018, long term sub-bituminous solicitation, a review of Plant Scherer's inventory plan and burn projections for 2019 through 2022 indicated a need to purchase a sub-bituminous coal. The applicable bids received were evaluated on a fully delivered $/MMBtu basis, including the value of sulfur. In support of the evaluation process, transportation rates and SO2 allowance values were provided and included as part of the analysis. Other inputs to the evaluation included railcar lease and maintenance and dust suppression costs.

An evaluation to derive a delivered $/MMBtu least cost line-up was performed using applicable transportation rates and emission allowance values. After reviewing the offers, a competitive buy line was established utilizing the most economical offers. The least cost offers received from these bids came from Blackjewel and Peabody. The bid from Peabody's Rawhide mine was dismissed because the quality does not meet the minimum spec at Scherer. The bids from Blackjewel and Peabody's Caballo mines were selected as the least-cost meeting the required quality for Scherer.

From Blackjewel, it was determined to procure approximately 142,000 tons for delivery in 2019 at [redacted] 142,000 tons for delivery in 2020 at [redacted] 160,000 tons for delivery in 2021 at [redacted] and 160,000 tons for delivery in 2022 at [redacted]
From Peabody it was determined to procure approximately 460,000 tons for delivery in 2019 at [redacted] 460,000 tons for delivery in 2020 at [redacted] 140,000 tons for delivery in 2021 at [redacted] and 140,000 tons for delivery in 2022 at [redacted]

AUGUST 6, 2018 SHORT-TERM RFP

Regarding the August 6, 2018, sub-bituminous solicitation, a review of Plant Scherer's inventory plan and burn projections for October through December 2018 indicated a need to purchase a sub-bituminous coal for delivery in October through December 2018. The applicable bids received were evaluated on a fully delivered $/MMBtu basis, including the value of sulfur. In support of the evaluation process, transportation rates and SO2 allowance values were provided and included as part of the analysis. Other inputs to the evaluation included railcar lease and maintenance and dust suppression costs.
An evaluation to derive a delivered $/MMBtu least cost line-up was performed using applicable transportation rates and emission allowance values. After reviewing the offers, a competitive buy line was established utilizing the most economical offers. The least cost offer received from these bids came from Kiewit Mining Group's Buckskin Mine delivering at [redacted] It was determined to procure approximately 240,000 tons for delivery October through December 2018.

AUGUST 31, 2018 LONG-TERM RFP

Regarding the August 31, 2018 long term sub-bituminous solicitation, a review of Plant Scherer's inventory plan and burn projections for 2019 through 2022 indicated a need to purchase sub-bituminous coal. The applicable bids received were evaluated on a fully delivered $/MMBtu basis, including the value of sulfur. In support of the evaluation process, transportation rates and SO2 allowance values were provided and included as part of the analysis. Other inputs to the evaluation included railcar lease and maintenance and dust suppression costs.

An evaluation to derive a delivered $/MMBtu least cost line-up was performed using applicable transportation rates and emission allowance values. After reviewing the offers, a competitive buy line was established utilizing the most economical offers. The least cost offers received from these bids came from Blackjewel and Peabody's Rawhide mine. The bids from Blackjewel and Peabody's Rawhide mine were dismissed due to quality issues with the coal. Kiewit Mining Group's Buckskin mine and Peabody's Caballo mine were selected for the purchase. From Kiewit Mining Group/Buckskin it was determined to procure approximately 235,000 tons for delivery in 2019 at [redacted] 235,000 tons for delivery in 2020 at [redacted] 235,000 tons for delivery in 2021 at a negotiated price of [redacted] and 235,000 tons for delivery in 2022 at a negotiated price of [redacted] From Peabody it was determined to procure approximately 110,000 tons for delivery in 2019 at [redacted] 50,000 tons for delivery in 2020 at [redacted] 50,000 tons for delivery in 2021 at [redacted] and 50,000 tons for delivery in 2022 at [redacted]

3. During 2018, did Gulf experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.

ANSWER:

No.

Supply Bids Received - Fall 2018 RFP

4. For each RFP for natural gas issued in 2018 by Gulf, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline used for delivery.

ANSWER:

Southern Company Services (SCS), as agent for Alabama Power Company, Georgia Power Company, Mississippi Power Company, Gulf Power Company and Southern Power Company, solicited bids in Summer and Fall of 2018 for firm, base load natural gas supply to assist in serving the fuel requirements of its affiliates.

Supply Bids Received - Summer 2018 RFP

A	B	C	E	F	G	H
Bidder	**Pipeline**	**Point**	**Vol. (000)**	**Price**	**Beg. Date**	**End Date**
Eco-Energy	GSPL	Bosco	[redacted]		Jul-18	Aug-18
BP	GSPL	Carthage			Jul-18	Aug-18
Texla	GSPL	Carthage			Jul-18	Aug-18
CIMA	GSPL	Delhi Centerpoint			Jul-18	Aug-18
Twin Eagle	GSPL	Perryville			Jul-18	Aug-18
Uniper	GSPL	Perryville			Jul-18	Aug-18
Texla	GSPL	Perryville			Jul-18	Aug-18
Sequent	GSPL	Pooling Area #17			Jul-18	Aug-18
Shell	GSPL	Pooling Area #17			Jul-18	Aug-18
BP	GSPL	Pooling Area #17			Jul-18	Aug-18

Supply Bids Received - Fall 2018 RFP

A	B	C	D	E	F	G
Bidder	**Pipeline**	**Point**	**Vol. (000)**	**Price**	**Begin Date**	**End Date**
DTE	Transco	Pine View	[redacted]		Jun-19	May-20
XTO	Transco	Pine View			Jun-19	Oct-22
XTO	Transco	Pine View			Aug-19	Oct-22
XTO	Transco	Scott Mountain			Sep-19	Oct-24
Devon	Transco	Scott Mountain			Jun-19	May-22
Devon	Transco	Scott Mountain			Jun-19	May-22
Southwest Energy	Transco	Scott Mountain			Jun-19	May-20
Uniper	Transco	Scott Mountain			Jun-19	Oct-22
Mercuria	Transco	Scott Mountain			Jun-19	May-21
Mercuria	Transco	Scott Mountain			Jun-19	May-22
Uniper	Transco	85 Pool			Jun-19	May-20
Sequent	Transco	85 Pool			Jun-19	May-20
Sequent	Transco	85 Pool			May-19	Sep-19
ConocoPhillips	Transco	85 Pool			May-19	Sep-19
ConocoPhillips	Transco	85 Pool			Jun-19	May-20
Spire	Transco	85 Pool			Jun-19	May-20
Macquarie Energy	Transco	85 Pool			Jun-19	Sep-19
Constellation	Transco	85 Pool			May-19	Sep-20
Koch Energy	Transco	85 Pool			May-19	Sep-19
Biourja Trading	Transco	85 Pool			May-19	Sep-19
Southwest Energy	Transco	85 Pool			Jun-19	May-20
XTO	Transco	85 Pool			Jun-19	Mar-21
Koch Energy	Transco	85 Pool			Jun-19	May-20
BP Energy Company	Transco	85 Pool			Jun-19	May-21
BP Energy Company	Transco	85 Pool			May-19	Sep-19
EDF	Transco	85 Pool			Jun-19	May-20
DTE	Transco	85 Pool			May-19	Sep-19
DTE	Transco	85 Pool			Jun-19	May-20
Biourja Trading	Transco	85 Pool			Jun-19	Sep-20
Direct	Transco	85 Pool			Jun-19	May-20
Direct	Transco	85 Pool			May-19	Sep-19
Uniper	Transco	85 Pool			Jun-19	Oct-22
Direct	Transco	85 Pool			Jun-19	May-21
Twin Eagle	Transco	85 Pool			Jun-19	May-21
Twin Eagle	Transco	85 Pool			May-19	Sep-19
Shell	Transco	85 Pool			May-19	Sep-21

5. Please describe the action taken for each bid identified in response to Interrogatory No. 4. Include in your response an explanation of the evaluation process and how successful proposals were selected.

ANSWER:

After reviewing the gas supply needs, each bid was evaluated based on price, location, volume, term, transportation rights (firm or interruptible) and the flexibility of supply.

Supply Bids Accepted - Summer 2018 RFP

A	B	C	D	E	F	G
Bidder	**Pipeline**	**Point**	**Vol. (000)**	**Price**	**Beg. Date**	**End Date**
Sequent	GSPL	Pooling Area #17	[redacted]		July-18	Aug-18

Supply Bids Accepted - Fall 2018 RFP

A	B	C	D	E	F	G
Bidder	**Pipeline**	**Point**	**Vol. (000)**	**Price**	**Beg. Date**	**End Date**
DTE	Transco	Pine View	[redacted]		Jun-19	May-20
XTO	Transco	Pine View			Jun-19	Oct-22
XTO	Transco	Pine View			Aug-19	Oct-22
XTO	Transco	Scott Mountain			Sep-19	Oct-24
Devon	Transco	Scott Mountain			Jun-19	May-22
Devon	Transco	Scott Mountain			Jun-19	May-22
Uniper	Transco	85 Pool			Jun-19	May-20
Sequent	Transco	85 Pool			May-19	Sep-19

6. In 2018, did Gulf participate in any capacity discussions or bid for any firm pipeline capacity during "open season?" Please explain your response and identify the pipeline companies.

ANSWER:

Yes. A firm pipeline capacity contract for 15,000 MMBtu/day to Plant Crist on Gulf South Pipeline (GSPL) had an expiration date of May 31, 2018, subject to right of first refusal (ROFR). On January 30, 2018, GSPL provided notice on their Electronic Bulletin Board they would accept bids for the firm capacity subject to ROFR. The bidding period closed with no bids. SCS extended the firm capacity contract at GSPL's maximum tariff rate from June 1, 2018 – May 31, 2021.

7. In 2018, did Gulf participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

ANSWER:

No.

DECLARATION

I sponsored the answers to Interrogatory Nos. 1 through 7 from **STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-7)** to Gulf Power Company in Docket No. 20190001-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.

Charles Howton

Date: 3-15-19

96

Gulf's Response to Staff's Second Set of Interrogatories, Nos. 8-16

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 96
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Shane Boyett (8-15), C. Shane Boyett (16)

8. Please describe the steps the Company undertook to prepare the fuel price forecast the Company prepared to support its 2019 projections, as filed on August 24, 2018, in Docket No. 20180001. Discuss in your response when these steps were started and when these steps were concluded, and how the timeline for preparing this forecast compared to the timeline for preparing the similar forecasts for 2017 or 2018.

ANSWER:

Consistent with fuel price forecasts developed for 2017 and 2018, the Southern Electric System (SES), on behalf of Gulf Power, prepared the short-term (current year +2) and long-term (year 4 and beyond) fuel price forecasts which extend through the Company's 10-year planning horizon and longer for resource planning. The short-term forecasts were developed by Southern Company Services (SCS) Fuel Services in June of each year for use in the system's fuel budgeting process and marginal pricing dispatch procedures. The long-term commodity forecasts were developed in the spring of each year for use in system planning activities. Charles River Associates (CRA) is the consultant that was used to develop long-term commodity forecasts utilizing a proprietary macro-economic model. The collaborative process between CRA and members of cross-functional SES planning teams, including Gulf Power personnel, and was governed by an SES executive team.

Fuel market-driving assumptions, developed in collaboration between CRA and SES personnel, were integrated into CRA's model to develop commodity forecast prices. These commodity forecasts were compared to both proprietary and public forecasts for reasonableness. Transportation prices were developed by SES personnel and were combined with the CRA commodity prices to produce the total delivered price forecast.

The delivered price of any fuel consists of a variety of components. The main components are commodity price and transportation cost. Domestic coal commodity prices are forecast on either a mine-mouth basis or free on board (FOB) barge basis, while import coals are forecast on an FOB ship basis at the port of import. Natural gas prices are forecast at the Henry Hub, Louisiana benchmark delivery point. Because mine-mouth coal prices vary by source, sulfur content, and Btu level, SES prepared commodity price forecasts for different coal classifications used on the SES. Because natural gas does not possess the same quality variations as coal, SES prepared a single commodity price forecast for natural gas at Henry Hub, and applied a basis differential between Henry Hub and the various pipelines serving SES plants.

Transportation costs, used in the delivered price forecast, were developed for potential sites when modeling generic unit additions in the resource planning process. Site-specific transportation costs were developed for existing units to produce delivered price forecasts for the fuel budget process. Similarly, when site-specific unit additions are under consideration, site-specific transportation costs were developed for each option.

9. How often are fuel price forecasts prepared? Discuss in your response what triggers, or market observations would prompt the Company to update its fuel price forecast.

ANSWER:

Fuel price forecasts are prepared each year to support the annual energy budget process. For further details, see Gulf's response to Interrogatory No. 8.

10. If known, identify the date the next fuel price forecast is scheduled to be prepared.

ANSWER:

Please see Gulf's response to Interrogatory No. 8.

11. Please identify the forecasting sources that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

ANSWER:

Please see Gulf's response to Interrogatory No. 8.

12. Were any of the sources identified in the response to Interrogatory number 12 new or different than the sources used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

ANSWER:

No. For purposes of Gulf's reply to this interrogatory, it is assumed that the question is intended to refer to Interrogatory No. 11.

13. Please identify the forecasting assumptions that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

ANSWER:

For coal, current proprietary market quotes and bids from various vendors were used. For gas, current NYMEX market prices were used. For further details, see Gulf's response to Interrogatory No. 8.

14. Were any of the assumptions identified in the response to Interrogatory number 14 new or different than the assumptions used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

ANSWER:

No. For purposes of Gulf's reply to this interrogatory, it is assumed that the question intended to refer to Interrogatory No. 13.

15. Discuss how the Company incorporates recognized, authoritative independent forecasts into its fuel price forecasts.

ANSWER:

As discussed in Gulf's response to Interrogatory No. 8, CRA's long-term forecast is the only forecast incorporated in the company's fuel price forecasts. For comparison purposes, other commodity fuel price forecasts were reviewed from recognized independent consulting firms for natural gas and coal. Forecasts from independent consulting firms reviewed included Energy Ventures Analysis (EVA), Inc. for domestic and import coals, and Energy Ventures Analysis (EVA), Inc. and JPMorgan for natural gas and LNG.

Comparisons of the fuel price forecasts were made against each fuel price forecast of the consulting firms listed above, as well as other sources which were used (AEO, NYMEX) to gain information about fuel markets.

16. Please refer to the Company's January 2019 A-Schedule filing, and specifically to Schedule A-1, Line 15, reporting Transmission and Distribution (T & D) Losses.
    a. Please show the mathematical inputs and/or the calculations that were performed in order to produce the dollar values (shown in Columns A-C) for T & D Losses in this period.
    b. An actual dollar value of $1,657,596 for T & D Losses was recorded in Column A for this period. Please explain the variance shown between the recorded dollar value for T & D Losses and the estimated dollar value for T & D Losses in this period.
    c. Please show the mathematical inputs and/or the calculations that were performed in order to produce the quantity of kilowatt-hours (shown in Columns E-G) for T & D Losses in this period.
    d. An actual quantity of 49,821,036 kilowatt-hours for T & D Losses was recorded for this period. Please explain the variance shown between the recorded quantity and the estimated quantity of kilowatt-hours for T & D Losses in this period.
    e. Schedule A-1, Line 13, reports that the Total Fuel and Net Power Transactions was over 5 percent higher than estimated amounts for dollars, and a little over 1 percent higher than estimates for kilowatt-hours. Please explain why T & D Losses (shown on Line 15) are higher by a larger percentage for dollars and kilowatt-hours, than the entries for Line 21.

ANSWER:

A.

1. $Losses\ kWh * Total\ Fuel\ and\ Net\ Power\ Transactions\ (cents\ per\ kWh) \div 100 = Costs\ Attributed\ to\ T\&D\ losses$

$$49{,}821{,}036\ kWh * 3.3271¢ \div 100 = \$1{,}657{,}596$$

B. The variance in T&D losses for January 2019 was driven by higher than projected quantity of energy losses and higher than projected average fuel costs (cents per kWh) for the month. The higher average fuel and net power transactions costs (cents per kWh) is due to higher than projected cost of natural gas for the month. The higher than projected quantity of energy losses is, in part, due to the method of estimation employed by Gulf Power. The company projects T&D losses based on the annual average loss factor from the prior 3 years. However, actual T&D losses as a percentage of total kWh sales exhibit significant volatility from month to month. Therefore, actual losses for any individual month may differ significantly

from projections. The higher price per kWh along with the actual losses being higher than projected results in the variance shown on Schedule A-1, line 15, column C.

C.

Net Territorial Supply				940,579,677
Less: Total Territorial Sales				
		Residential	448,568,579	
		Commercial	577,353,454	
		Industrial	136,190,578	
		Street Lighting	2,675,747	
		Sales for Resale	24,797,417	(889,585,775)
Less: Company Use				(1,175,866)
T&D Losses				49,821,036

D. Please see item B above.

E. Please see item B above.

DECLARATION

I sponsored the answers to Interrogatory Nos. 8 through 15 from **STAFF'S SECOND SET OF INTERROGATORIES (NOS. 8-16)** to Gulf Power Company in Docket No. 20190001-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.

Charles Howton

Date: 3-29-19

DECLARATION

I sponsored the answer to Interrogatory No. 16 from **STAFF'S SECOND SET OF INTERROGATORIES (NOS. 8-16)** to Gulf Power Company in Docket No. 20190001-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.

C. Shane Boyett

C. Shane Boyett

Date: April 1, 2019

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TECO's Response to Staff's First Set of Interrogatories, Nos. 1-7

CONFIDENTIAL DN. 03169-2019

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 97
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: John Heisey

1. For each Request for Proposal (RFP) for coal issued in 2018 by or on behalf of TECO, list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

A. In 2018, Tampa Electric issued two RFP's for solid fuel. Tampa Electric issued Gen 2018-02 for spot tonnages of Rail Coal. The bids received with this solicitation are described below. Tampa Electric purchased 315,000 tons through this solicitation as further described in the company's response to Interrogatory No. 2.

REDACTED

GEN 2018-01

Supplier	Tonnage Bid	Btu/lb	Ash (Lbs)	Moisture (%)	Chlorine (%)	$/Ton Delivered	$/MMBtu Delivered	Delivery Method	Delivery Route	Awarded
[redacted]										
										X

Tampa Electric also issued Gen 2019-01 for spot 2019 rail and waterborne supply. The bids received with this solicitation are described below. Tampa Electric purchased 680,000 tons through this solicitation as further described in the company's response to Interrogatory No. 2.

REDACTED

GEN 2019-01

Supplier	Tonnage Bid	Btu/lb	Ash (Lbs)	Moisture (%)	Chlorine %	$/Ton Delivered	$/MMBtu Delivered	Delivery Method	Delivery Route	Awarded
[redacted]										
										x
										x

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
STAFF'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 2
PAGE 1 OF 1
FILED: MARCH 18, 2019

2. Please describe the action taken for each bid identified in response to Interrogatory No. 1. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. All bids were evaluated based on the total delivered cost per mmBtu. Tampa Electric identified a short list of qualifying bids based on projected commodity and transportation costs, quality, proposed terms and conditions, blending impacts, supplier reliability and supplier financial strength. Qualifying bids accounting for operational impacts as well as containing acceptable quality, terms and conditions and supplier reliability as specified in the RFP were considered. Once qualifying bids were identified, Tampa Electric selected the quality adjusted, lowest priced alternative on a utilized, portfolio basis.

As indicated in the company's response to Interrogatory No. 1, Tampa Electric issued RFP Gen 2018-02 on February 5, 2018, for spot domestic high sulfur coal commodity with the expectation of transporting the coal to Tampa using the existing rail contract with CSX. Tampa Electric received seven offers for coal from the Illinois Basin and also from the Northern Appalachian coal mines. Tampa Electric purchased 315,000 tons from [redacted] for 2018. [redacted]

Tampa Electric also issued RFP 2019-01 on September 26, 2018 for spot domestic high sulfur coal to be delivered in 2019. Tampa Electric solicited for all coals suited for Big Bend Station with the objective of purchasing coal commodity to be transported from either rail, waterborne, or bi-modal mines. As an option, this RFP allowed bidders to offer the transportation of the commodity to the Big Bend Station - FAS Big Bend (Free Alongside Ship). In response, Tampa Electric received eleven commodity offers with nine being rail served of which two were bi-modal. Two offers were received from waterborne sources with one offer made on a delivered basis to Tampa, FAS Big Bend. Tampa Electric made two purchases from the solicitation. Tampa Electric purchased 480,000 delivered waterborne tons from [redacted] directly into Big Bend Station. Tampa Electric also purchased 200,000 tons of coal from [redacted] delivered into a railcar. [redacted]

3. During 2018, did TECO experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.

A. Yes, the company experienced detention and demurrage charges. During 2018, except for the three named storms in the Gulf of Mexico that restricted vessel movement, there were not any unusual or singularly identifiable events such as floods, strikes or equipment failures that caused or contributed to the demurrage and detention charges. Instead the demurrage and detention charges resulted from the normally occurring operational constraints associated with the delivery and handling of bulk commodities. Each Vessel or truck may have encountered one or more issues, sometimes compounding across multiple vessels. The issues that caused the charges including stacker or reclaimer failures, dock or coal field belt repairs, channel navigation restrictions, inclement weather, unloaded equipment failure, communication equipment issues, shifting vessel, blending coal as it comes off the vessel, and waiting for a completion of a vessel at the dock. The chart below summarizes the demurrage charges incurred in 2018.

REDACTED

Date	Vessel/Truck	Demurrage
1/7/2018	[redacted]	
1/12/2018		
1/17/2018		
2/9/2018		
2/10/2018		
2/14/2018		
3/1/2018		
4/18/2018		
4/19/2018		
4/30/2018		
5/8/2018		
5/21/2018		
5/21/2018		
5/23/2018		
5/26/2018		
5/26/2018		
5/28/2018		
5/28/2018		
6/5/2018		
6/10/2018		
6/10/2018		
6/11/2018		
6/12/2018		
6/15/2018		
6/15/2018		
6/21/2018		
6/22/2018		
6/22/2018		
6/25/2018		
6/25/2018		
6/28/2018		
6/28/2018		
6/30/2018		
7/4/2018		
7/4/2018		
7/9/2018		
7/9/2018		
7/13/2018		
7/13/2018		
7/17/2018		
7/17/2018		
7/25/2018		
7/31/2018		
8/19/2018		
8/25/2018		

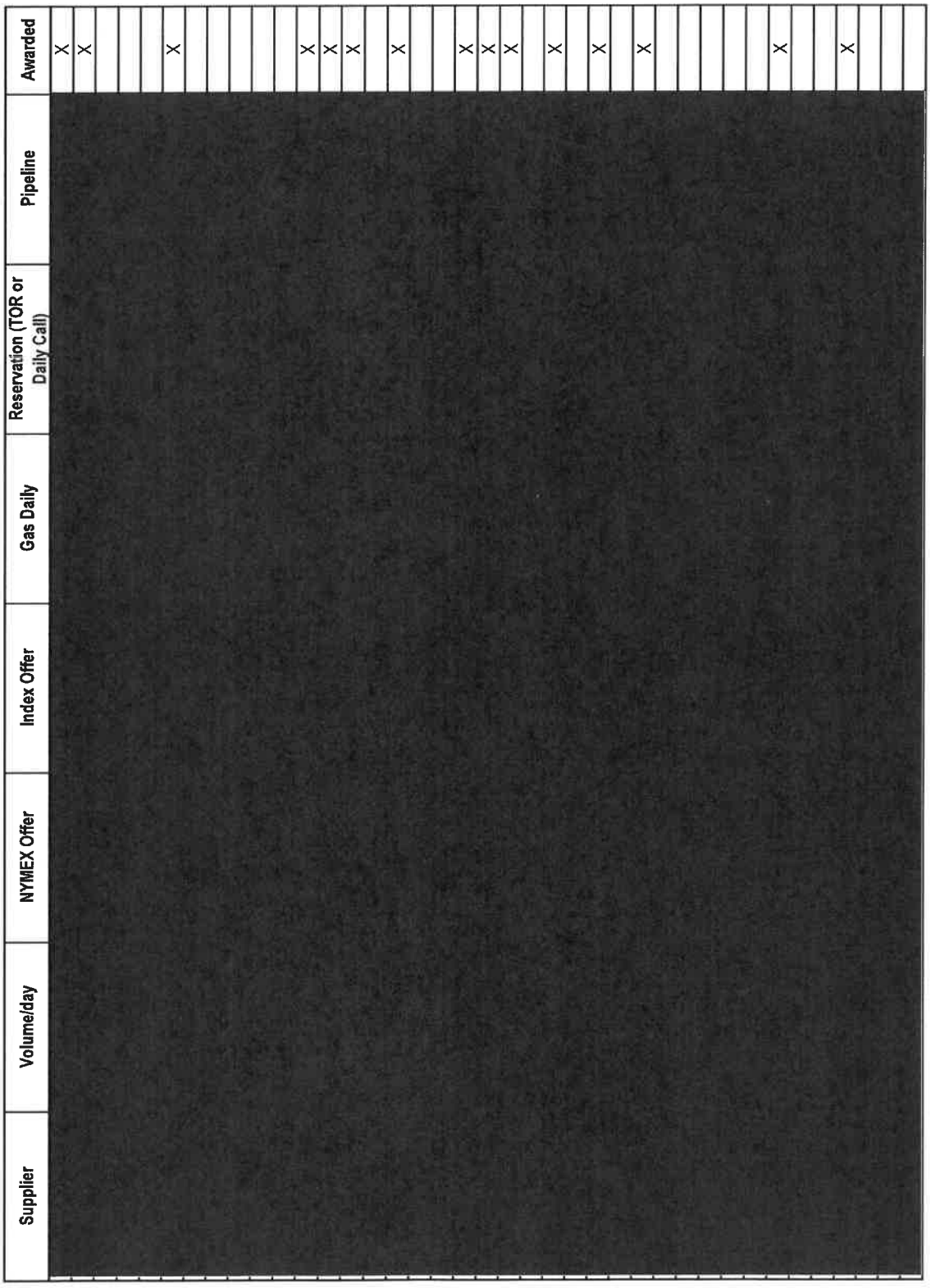
REDACTED

Date	Vessel/Truck	Demurrage
8/25/2018	[redacted]	[redacted]
8/31/2018		
9/7/2018		
9/7/2018		
10/7/2018		
10/7/2018		
10/8/2018		
10/23/2018		
10/23/2018		
10/25/2018		
10/25/2018		
11/26/2018		
11/26/2018		
12/6/2018		
12/24/2018		

4. For each RFP for natural gas issued in 2018 by TECO, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline used for delivery.

A. The requested information is provided in the following table.

REDACTED



Supplier	Volume/day	NYMEX Offer	Index Offer	Gas Daily	Reservation (TOR or Daily Call)	Pipeline	Awarded
							X
							X
							X
							X
							X
							X
							X
							X
							X
							X
							X
							X
							X
							X

REDACTED

Supplier	Volume/day	NYMEX Offer	Index Offer	Gas Daily	Reservation (TOR or Daily Call)	Pipeline	Awarded
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X

5. Please describe the action taken for each bid identified in response to Interrogatory No. 4. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. Tampa Electric issued one RFP for natural gas supply in 2018. The RFP was issued in September 2018, and Tampa Electric sent the RFP to approximately 87 qualified suppliers. In response to the RFP, Tampa Electric received approximately 72 gas supply package options from 14 respondents. Each gas supply option was evaluated based on price, pipeline, receipt point, supply type, firmness, term, and special conditions. Special conditions included the following items:

- Pipeline optionality, or the ability to move supply from one pipeline to another at Tampa Electric's option;
- Volume flexibility, or the ability to adjust the daily baseload gas volume at the beginning of each month; and
- Pricing conversion, and indexed gas price that can be converted to a fixed price at Tampa Electric's request

Tampa Electric grouped the packages by term (*e.g.*, winter/summer packages), gas supply type (*e.g.*, baseload, swing, or peaking), and pipeline. For each group, the packages were ranked by price. Special provisions and strategic considerations related to price and supplier risk were considered. The company selected the lowest cost supply packages considering reliability, optionality, and flexibility. Finally, Tampa Electric contacted the selected suppliers to execute a deal confirmation. If an agreement could not be reached, the next best vendor was contacted.

As a result of the 2018 RFP, ten vendors were awarded a total of 3,383 to 50,000 MMBtu per day, depending on the season. The selected packages included baseload, monthly take or release and daily call options with various time frames and delivery based on different pipelines.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
STAFF'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 6
PAGE 1 OF 1
FILED: MARCH 18, 2019

6. In 2018, did TECO participate in any capacity discussions or bid for any firm pipeline capacity during "open season?" Please explain your response and identify the pipeline companies.

A. Yes. In 2018, Tampa Electric bid for firm pipeline capacity during "open seasons" on Gulfstream Natural Gas System and Sabal Trail Transmission. Tampa Electric was successful in acquiring 20,000 MMBtu per day of firm pipeline capacity on Sabal Trail Transmission from 7/1/18 to 8/31/18 and from 9/1/18 to 5/31/21. [redacted]

7. In 2018, did TECO participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

A. Yes. In 2018, Tampa Electric evaluated 10 natural gas storage facilities in its effort to replace existing firm storage agreements that expired on March 31, 2018. After an initial screening, Tampa Electric requested proposals and engaged in discussions with Bay Gas Storage, Mississippi Hub Storage, and Southern Pines. As a result of the discussions, firm storage agreements were executed with Bay Gas Storage (1.5 BCF) and Southern Pines (0.5 BCF) for a term of five years ending March 31, 2023.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared John Heisey who deposed and said that he is a Manager, Gas and Power Trading, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (Nos. 1-7) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 18 day of March, 2019.

Sworn to and subscribed before me this 18th day of March, 2019.

Notary Public State of Florida
Sana Boric
My Commission GG 020235
Expires 08/10/2020

My Commission expires _____

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TECO's Response to Staff's Second Set of Interrogatories, Nos. 8-16

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 98
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: John Heisey (8-15) Penelope Rusk (16)

8. Please describe the steps the Company undertook to prepare the fuel price forecast the Company prepared to support its 2019 projections, as filed on August 24, 2018, in Docket No. 20180001. Discuss in your response when these steps were started and when these steps were concluded, and how the timeline for preparing this forecast compared to the timeline for preparing the similar forecasts for 2017 or 2018.

A. Preparation of the fuel price forecast must occur at the beginning of the process for preparing the fuel clause projection for filing, including the 6-month actual/6-month estimated filing that is submitted in July. The fuel price forecast process typically begins in May. Depending on other workload, the process may slip into June, which is considered undesirable as it greatly compresses the preparation and review time for the entire filing, or begin earlier than May, which is preferred.

The preparation of the 2019 fuel price forecast started in April 2018, compared to the 2017 and 2018 fuel price forecasts which were prepared in May 2017 and June 2016, respectively. The 2019 fuel price forecast was prepared earlier so that it could be used in the Second SoBRA cost-effectiveness filing.

Tampa Electric reviews fuel price forecasts from sources used in the industry, including the New York Mercantile Exchange ("NYMEX"), PIRA Energy, the Energy Information Administration, and other energy market information sources. Future prices for energy commodities as traded on NYMEX, averaged across five consecutive business days in the late spring/early summer, form the basis of the natural gas and No. 2 oil market commodity price forecasts. The price projections for these two commodities are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry recognized consultants and published indices. Also, the price projections are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity price and associated transportation costs.

Petroleum coke commodity pricing is determined from forward market curves that follow international market prices of coal on a per Btu basis.

9. How often are fuel price forecasts prepared? Discuss in your response what triggers, or market observations would prompt the Company to update its fuel price forecast.

A. Fuel price forecasts are prepared annually in the late spring/early summer timeframe ahead of the 6-month actual/6-month estimated filing that is submitted in July.

Fuel clause projections for the current year and the following year are monitored and reviewed monthly against actuals to date. To the extent that projected costs are expected to approach +/- 10% from the filed fuel clause projection, a new fuel price forecast is prepared and may result in the company filing a petition for Mid-Course Correction.

Natural gas prices have the greatest potential impact on the fuel price forecast and are monitored daily by the Wholesale Power, Planning and Fuels department. Significant changes in natural gas pricing are communicated internally so that impacts to fuel clause projections can be evaluated in a timely manner.

10. If known, identify the date the next fuel price forecast is scheduled to be prepared.

A. The fuel price forecast will be updated in the second quarter of 2019 to prepare the 2019 actual/estimated and 2020 projected costs and cost recovery factors.

11. Please identify the forecasting sources that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

A. Tampa Electric forecasts base case natural gas, coal, and oil fuel commodity prices by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, PIRA Energy Group, Coal Daily, Inside FERC, Platt's Oilgram, and the Energy Information Administration. These sources were used in the preparation of the company's 2019 projections.

12. Were any of the sources identified in the response to Interrogatory number 11 new or different than the sources used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

A. No.

13. Please identify the forecasting assumptions that were used for preparing the fuel forecast that was prepared to support the Company's 2019 projections.

A. The following assumptions were used in preparing the fuel forecast to support the company's 2019 projections:

The commodity fuel price forecast methodology and sources are described in the company's responses to Interrogatory Nos. 8, 11, and 15. Additional fuel cost assumptions are described below.

Natural Gas

- Pipeline variable charges (fuel, commodity, etc.) are based on current pipeline variable charges at the time of the fuel forecast.
- Supply basis is determined by current forward market curves derived from market intelligence at the time of the fuel forecast.
- Delivered basis is based on current forward market curves derived from market intelligence and indications at the time of the fuel forecast; indexes are not available due to limited liquidity.
- Firm transport demand charges are set at the current pipeline demand charges at the time of fuel forecast, unless a negotiated rate is applicable.
- Firm transportation contracts are assumed to renew at the rates of the expired contract.

Solid Fuel

- Transportation rates and structure are based on current contract rates and forward estimates based on market intelligence.

Oil

- Transportation rates and structure are based on current contract rates and forward estimates based on market intelligence.

14. Were any of the assumptions identified in the response to Interrogatory number 13 new or different than the assumptions used in preparing the forecasts for 2017 or 2018? If so, provide a detailed response.

A. No.

15. Discuss how the Company incorporates recognized, authoritative independent forecasts into its fuel price forecasts.

A. Tampa Electric has used the same methodology to forecast fuel commodity prices for approximately ten years. The methodology is consistent across commodities. The company uses market indicators (*e.g.*, NYMEX futures contracts) to estimate near-term prices (one to three years). The methodology then uses a commercially available, published fuel commodity price forecast from an independent energy consulting firm (*e.g.*, PIRA, Wood MacKenzie) for the mid-term (two to 20 years). The final long-term portion of the fuel price forecast then transitions to using an independent, longer term source for the annual price changes (*e.g.*, EIA Long Term Energy Outlook). The source data is blended to transition between time periods. The forecast is produced in the second quarter of each year to support the summer fuel clause actual-estimate and projection filings and is used for one year until the next official forecast is produced.

16. Please refer to the Company's January 2019 A-Schedule filing, and specifically to Schedule A-1, Line 26, reporting Transmission and Distribution (T & D) Losses.

a. Please show the mathematical inputs and/or the calculations that were performed in order to produce the dollar values for T & D Losses in this period.

b. An actual dollar value of $2,603,020 for T & D Losses was recorded for this period. Please explain the variance shown between the recorded dollar value for T & D Losses and the estimated dollar value for T & D Losses in this period.

c. Please show the mathematical inputs and/or the calculations that were performed in order to produce the quantity of megawatt-hours for T & D Losses in this period.

d. An actual quantity of 76,045 megawatt-hours for T & D Losses was recorded for this period. Please explain the variance shown between the recorded quantity and the estimated quantity of megawatt-hours for T & D Losses in this period.

e. Schedule A-1, Line 19, reports that the Total Fuel Cost and Gains of Power Sales was over 200 percent higher than estimated amounts for dollars and for megawatt-hours. Please explain why the percentages for T & D Losses (shown on Line 26) are much lower percentage than the entries for Line 19.

A. Please refer to the attached January 2019 Schedules A1 and A2 for the following:

a. Dollar values for T&D Losses on Line 26 are calculated as follows.
Actual: (76,045 x 3.42300) x 10
Estimated: (86,990 x 2.89636) x 10
Total: Sch. A1 (Line 26 MWh x Line 23 cents/kWh) x 10

b. In January, fuel expense was greater than estimated due to higher gas unit cost and greater gas burned than estimated. The increase was offset somewhat by lower economy purchases than estimated, which resulted in greater cents/kWh than estimated on line 23. Also contributing to the increase was greater than expected unbilled energy. These factors account for the T&D losses dollar variance of $83,481 on line 26.

Actual:	$2,603,020
Estimated:	2,519,539
Variance:	$ 83,481

c. Megawatt hour values for T&D Losses on Line 26 are calculated as follows.

Actual:	1,499,254 - 5,946 + (58) + 1,004 - 1,142 - 4,524 - 3,019 - 1,409,524
Estimated:	1,516,920 - 1,930 + 0 + 0 – 44 - (75,108) - 3,100 - 1,499,964
Total:	Sch. A1 (Line 13 - Line 19 + Line 20 + Line 21 - Line 22 - Line 24 - Line 25) - Sch. A2 (page 1 of 3, Line B1)

d. T&D loss calculations begin with Fuel and Net Power Transaction megawatt hours and subtract the change in unbilled volumes and company use volumes to arrive at T&D Losses for actual and estimated megawatt hours. The variance results from a comparison of the two, as follows.

Actual:	$76,045
Estimated:	86,990
Variance:	($10,945)

e. Differences in the variance percentages are due to the following: Line 19 represents a subset of total Fuel and Net Power Transactions, Gains on Power Sales, while T&D loss percentages on Line 26 are based on the total. Line 26 is calculated using line 23 and not line 19. Line 23 does include line 19 but also includes lines 5, 12, 20, 21, and 22.

The calculation for line 23 is (Line 5 + Line 12 – Line 19 + Line 20 + Line 21 – Line 22).

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: January 2019

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	49,606,343	41,958,073	7,648,270	18.2%	1,463,774	1,456,450	7,324	0.5%	3.38893	2.88085	0.50809	17.6%
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	383,847	383,847	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments - Polk 1 Conversion Depreciation & ROI	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)	**49,990,190**	**42,341,920**	**7,648,270**	**18.1%**	**1,463,774**	**1,456,450**	**7,324**	**0.5%**	**3.41516**	**2.90720**	**0.50796**	**17.5%**
6. Fuel Cost of Purchased Power - Firm (A7)	35,101	0	35,101	0.0%	451	0	451	0.0%	7.78293	0.00000	7.78293	0.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	632,705	1,297,380	(664,675)	-51.2%	11,300	52,780	(41,480)	-78.6%	5.59916	2.45809	3.14107	127.8%
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)	621,159	290,630	330,529	113.7%	23,729	7,690	16,039	208.6%	2.61772	3.77932	(1.16160)	-30.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**1,288,965**	**1,588,010**	**(299,045)**	**-18.8%**	**35,480**	**60,470**	**(24,990)**	**-41.3%**	**3.63293**	**2.62611**	**1.00682**	**38.3%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,499,254**	**1,516,920**	**(17,666)**	**-1.2%**				
14. Fuel Cost of Sch. D Junsd. Sales (A6)	64,302	19,580	44,722	228.4%	2,837	820	2,017	246.0%	2.26655	2.38780	(0.12126)	-5.1%
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)	71,957	28,415	43,542	153.2%	3,109	1,110	1,999	180.1%	2.31447	2.56991	(0.24544)	-9.6%
18. Gains on Sales	33,686	3,659	30,029	820.7%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**169,947**	**51,654**	**118,293**	**229.0%**	**5,946**	**1,930**	**4,016**	**208.1%**	**2.85817**	**2.67637**	**0.18180**	**6.8%**
20. Net Inadvertant Interchange					(58)	0	(58)	0.0%				
21. Wheeling Rec'd. less Wheeling Deliv'd.					1,004	0	1,004	0.0%				
22. Interchange and Wheeling Losses					1,142	44	1,098	2486.8%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**51,109,208**	**43,878,276**	**7,230,932**	**16.5%**	**1,493,112**	**1,514,946**	**(21,834)**	**-1.4%**	**3.42300**	**2.89636**	**0.52664**	**18.2%**
24. Net Unbilled	154,856 (a)	(2,175,398) (a)	2,330,254	-107.1%	4,524	(75,108)	79,632	-106.0%	3.42299	2.89636	0.52663	18.2%
25. Company Use	103,340 (a)	89,787 (a)	13,553	15.1%	3,019	3,100	(81)	-2.6%	3.42299	2.89635	0.52663	18.2%
26. T & D Losses	2,603,020 (a)	2,519,539 (a)	83,481	3.3%	76,045	86,990	(10,945)	-12.6%	3.42300	2.89636	0.52664	18.2%
27. System KWH Sales	51,109,208	43,878,276	7,230,932	16.5%	1,409,524	1,499,964	(90,440)	-6.0%	3.62599	2.92529	0.70070	24.0%
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	51,109,208	43,878,276	7,230,932	16.5%	1,409,524	1,499,964	(90,440)	-6.0%	3.62599	2.92529	0.70070	24.0%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	51,109,208	43,878,276	7,230,932	16.5%	1,409,524	1,499,964	(90,440)	-6.0%	3.62599	2.92529	0.70070	24.0%
32. Adjustment-BB Unit 2 Outage Replacement Power Cost T-up	0	0	0	0.0%	1,409,524	1,499,964	(90,440)	-6.0%	0.00000	0.00000	0.00000	0.0%
33. True-up *	(584,624)	(584,624)	0	0.0%	1,409,524	1,499,964	(90,440)	-6.0%	(0.04148)	(0.03898)	(0.00250)	6.4%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	50,524,584	43,293,652	7,230,932	16.7%	1,409,524	1,499,964	(90,440)	-6.0%	3.58451	2.88631	0.69820	24.2%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	50,560,962	43,324,823	7,236,139	16.7%	1,409,524	1,499,964	(90,440)	-6.0%	3.58709	2.88839	0.69870	24.2%
37. GPIF * (Already Adjusted for Taxes)	(188,418)	(188,418)	0	0.0%	1,409,524	1,499,964	(90,440)	-6.0%	(0.01337)	(0.01256)	(0.00081)	6.4%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**50,372,544**	**43,136,405**	**7,236,139**	**16.8%**	**1,409,524**	**1,499,964**	**(90,440)**	**-6.0%**	**3.57372**	**2.87583**	**0.69789**	**24.3%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.574**	**2.876**	**0.698**	**24.3%**

* 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: January 2019

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	49,606,343	41,958,073	7,648,270	18.2%	1,463,774	1,456,450	7,324	0.5%	3.38893	2.88085	0.50809	17.6%
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	383,647	383,647	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments - Polk 1 Conversion Depreciation & ROI	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)	**49,990,190**	**42,341,920**	**7,648,270**	**18.1%**	**1,463,774**	**1,456,450**	**7,324**	**0.5%**	**3.41516**	**2.90720**	**0.50796**	**17.5%**
6. Fuel Cost of Purchased Power - Firm (A7)	35,101	0	35,101	0.0%	451	0	451	0.0%	7.78293	0.00000	7.78293	0.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	632,705	1,297,380	(664,675)	-51.2%	11,300	52,780	(41,480)	-78.6%	5.59916	2.45809	3.14107	127.8%
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)	621,159	290,630	330,529	113.7%	23,729	7,690	16,039	208.6%	2.61772	3.77932	(1.16160)	-30.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**1,288,965**	**1,588,010**	**(299,045)**	**-18.8%**	**35,480**	**60,470**	**(24,990)**	**-41.3%**	**3.63293**	**2.62611**	**1.00682**	**38.3%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,499,254**	**1,516,920**	**(17,666)**	**-1.2%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	64,302	19,580	44,722	228.4%	2,837	820	2,017	246.0%	2.26656	2.38780	(0.12126)	-5.1%
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 CATT 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)	71,957	28,415	43,542	153.2%	3,109	1,110	1,999	180.1%	2.31447	2.55991	(0.24544)	-9.6%
18. Gains on Sales	33,688	3,659	30,029	820.7%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18)	**169,947**	**51,654**	**118,293**	**229.0%**	**5,946**	**1,930**	**4,016**	**208.1%**	**2.85817**	**2.67537**	**0.18180**	**6.8%**
20. Net Inadvertant Interchange					(58)	0	(58)	0.0%				
21. Wheeling Rec'd. less Wheeling Deliv'd.					1,004	0	1,004	0.0%				
22. Interchange and Wheeling Losses					1,142	44	1,098	2496.6%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 19 + 20 + 21 - 22)	**51,109,208**	**43,878,276**	**7,230,932**	**16.5%**	**1,493,112**	**1,514,946**	**(21,834)**	**-1.4%**	**3.42300**	**2.89636**	**0.52664**	**18.2%**
24. Net Unbilled	154,856 (a)	(2,175,398) (a)	2,330,254	-107.1%	4,524	(75,108)	79,632	-106.0%	3.42299	2.89636	0.52663	18.2%
25. Company Use	103,340 (a)	89,787 (a)	13,553	15.1%	3,019	3,100	(81)	-2.6%	3.42299	2.89635	0.52663	18.2%
26. T & D Losses	2,603,020 (a)	2,519,539 (a)	83,481	3.3%	76,045	86,990	(10,945)	-12.6%	3.42300	2.89636	0.52664	18.2%
27. System KWH Sales	51,109,208	43,878,276	7,230,932	16.5%	1,409,524	1,499,964	(90,440)	-6.0%	3.62599	2.92529	0.70070	24.0%
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	51,109,208	43,878,276	7,230,932	16.5%	1,409,524	1,499,964	(90,440)	-6.0%	3.62599	2.92529	0.70070	24.0%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	51,109,208	43,878,276	7,230,932	16.5%	1,409,524	1,499,964	(90,440)	-6.0%	3.62599	2.92529	0.70070	24.0%
32. Adjustments - Schedule A2, page 2, lines 6c and 7a	0	0	0	0.0%	1,409,524	1,499,964	(90,440)	-6.0%	0.00000	0.00000	0.00000	0.0%
33. True-up *	(584,624)	(584,624)	0	0.0%	1,409,524	1,499,964	(90,440)	-6.0%	(0.04148)	(0.03898)	(0.00250)	6.4%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	50,524,584	43,293,652	7,230,932	16.7%	1,409,524	1,499,964	(90,440)	-6.0%	3.58451	2.88631	0.69820	24.2%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	50,560,962	43,324,623	7,236,139	16.7%	1,409,524	1,499,964	(90,440)	-6.0%	3.58709	2.88839	0.69870	24.2%
37. GPIF * (Already Adjusted for Taxes)	(188,418)	(188,418)	0	0.0%	1,409,524	1,499,964	(90,440)	-6.0%	(0.01337)	(0.01256)	(0.00081)	6.4%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**50,372,544**	**43,136,405**	**7,236,139**	**16.8%**	**1,409,524**	**1,499,964**	**(90,440)**	**-6.0%**	**3.57372**	**2.87583**	**0.69789**	**24.3%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.574**	**2.876**	**0.698**	**24.3%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

TAMPA ELECTRIC COMPANY
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STAFF'S SECOND SET OF
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INTERROGATORY NO. 16
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20190001.EI Staff Hearing Exhibits 00213

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: January 2019

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	49,606,343	41,958,073	7,648,270	18.2%	49,606,343	41,958,073	7,648,270	18.2%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	136,259	47,995	88,264	183.9%	136,259	47,995	88,264	183.9%
2a. GAINS FROM SALES	33,688	3,659	30,029	820.7%	33,688	3,659	30,029	820.7%
3. FUEL COST OF PURCHASED POWER	35,101	0	35,101	0.0%	35,101	0	35,101	0.0%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	621,159	290,630	330,529	113.7%	621,159	290,630	330,529	113.7%
4. ENERGY COST OF ECONOMY PURCHASES	632,705	1,297,380	(664,675)	-51.2%	632,705	1,297,380	(664,675)	-51.2%
5. TOTAL FUEL & NET POWER TRANSACTION	50,725,361	43,494,429	7,230,932	16.6%	50,725,361	43,494,429	7,230,932	16.6%
6a. ADJ. - BIG BEND UNITS 1-4 IGNITERS CONVERSION PROJECT	383,847	383,847	0	0.0%	383,847	383,847	0	0.0%
6b. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
6c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	51,109,207	43,878,276	7,230,931	16.5%	51,109,208	43,878,276	7,230,932	16.5%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,409,524	1,499,964	(90,440)	-6.0%	1,409,524	1,499,964	(90,440)	-6.0%
2. NONJURISDICTIONAL SALES	0	0	0	0.0%	0	0	0	0.0%
3. TOTAL SALES	1,409,524	1,499,964	(90,440)	-6.0%	1,409,524	1,499,964	(90,440)	-6.0%
4. JURISDIC. SALES-% TOTAL MWH SALES	1.0000000	1.0000000	0.0000000	0.0%	1.0000000	1.0000000	0.0000000	0.0%

TAMPA ELECTRIC COMPANY
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FILED: APRIL 1, 2019

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: January 2019

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	37,659,589	40,334,459	(2,674,870)	-6.6%	37,659,589	40,334,459	(2,674,870)	-6.6%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	584,624	584,624	0	0.0%	584,624	584,624	0	0.0%
2b. INCENTIVE PROVISION	188,418	188,418	0	0.0%	188,418	188,418	0	0.0%
2c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	38,432,631	41,107,501	(2,674,870)	-6.5%	38,432,631	41,107,501	(2,674,870)	-6.5%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	51,109,207	43,878,276	7,230,931	16.5%	51,109,207	43,878,276	7,230,931	16.5%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	1.0000000	1.0000000	0.0000000	0.0%	-	-	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	51,109,207	43,878,276	7,230,931	16.5%	51,109,207	43,878,276	7,230,931	16.5%
6a. JURISDIC. LOSS MULTIPLIER	1.00000	1.00000	0.00000	0.0%	-	-	-	-
6b. (LINE C6 x LINE C6a)	51,109,207	43,878,276	7,230,931	16.5%	51,109,207	43,878,276	7,230,931	16.5%
6c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
6d. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6c)	51,109,207	43,878,276	7,230,931	16.5%	51,109,207	43,878,276	7,230,931	16.5%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6d)	(12,676,576)	(2,770,775)	(9,905,801)	357.5%	(12,676,576)	(2,770,775)	(9,905,801)	357.5%
8. INTEREST PROVISION FOR THE MONTH	(87,639)	12,010	(99,649)	-829.7%	(87,639)	12,010	(99,649)	-829.7%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(36,970,912)	7,015,485	(43,986,397)	-627.0%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(584,624)	(584,624)	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(50,319,751)	3,672,096	(53,991,847)	-1470.3%	NOT APPLICABLE			

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
STAFF'S SECOND SET OF INTERROGATORIES
INTERROGATORY NO. 16
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FILED: APRIL 1, 2019

20190001.EI Staff Hearing Exhibits 00215

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: January 2019

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(36,970,912)	7,015,485	(43,986,397)	-627.0%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(50,232,112)	3,660,086	(53,892,198)	-1472.4%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(87,203,024)	10,675,571	(97,878,595)	-916.8%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(43,601,512)	5,337,786	(48,939,298)	-916.8%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	2.420	2.700	(0.280)	-10.4%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	2.410	2.700	(0.290)	-10.7%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	4.830	5.400	(0.570)	-10.6%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	2.415	2.700	(0.285)	-10.6%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.201	0.225	(0.024)	-10.7%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(87,639)	12,010	(99,649)	-829.7%	NOT APPLICABLE			

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
STAFF'S SECOND SET OF INTERROGATORIES
INTERROGATORY NO. 16
PAGE 7 OF 7
FILED: APRIL 1, 2019

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared John Heisey who deposed and said that he is a Manager, Gas & Power Trading, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (Nos. 8-16) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 27 day of March, 2019.

Sworn to and subscribed before me this 27th day of March, 2019.

Notary Public State of Florida
Tison C Vega
My Commission FF 955624
Expires 02/01/2020

My Commission expires _____

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is a Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (Nos. 8-16) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 28th day of March, 2019.

Penelope Rusk

Sworn to and subscribed before me this 28th day of March, 2019.

Notary Public State of Florida
Tison C Vega
My Commission FF 955624
Expires 02/01/2020

My Commission expires

99

TECO's Response to Staff's Third Set of Interrogatories, Nos. 17-18

CONFIDENTIAL DN. 09112-2019

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 99
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Penelope Rusk

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 17
PAGE 1 OF 1
FILED: SEPTEMBER 30, 2019

Questions 17-18 and subparts pertain to the Company's 2020 projections, as filed on September 3, 2019, in Docket No. 20190001-EI. Please refer to Schedule E12, Document No. 1, Page 4 of 4 of Exhibit PAR-3, and to the line(s) identified in each question.

17. On Document No. 1, Page 4 of 4, a double asterisk (**) is noted to indicate that a three year notification is required to terminate the long term SEMINOLE ELECTRIC contract.

a. What is the current term of TECO's agreement with SEMINOLE ELECTRIC?

b. Is the provision for the three-year notification applicable to either party, or only applicable to TECO? Please explain your response.

c. Has either party executed the three-year notification upon the other party? If so, please indicate the date(s)?

A. a. The contract between Tampa Electric and Seminole Electric is a non-firm contract that began in 1992. The original term was ten years with the contract continuing thereafter, unless terminated by either party with three years prior notice.

b. Either party may terminate the agreement by giving the other party three years notice.

c. Tampa Electric issued notice in December 2009 for a January 2013 termination date and retracted the notice prior to the termination date.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 20190001-EI
STAFF'S THIRD SET OF
INTERROGATORIES
INTERROGATORY NO. 18
PAGE 1 OF 1
FILED: SEPTEMBER 30, 2019

18. Schedule E12 indicates that the 12-month sum of projected capacity costs for 2020 ($560,376) is derived from 2 sources.

a. Please provide additional information about the "Seminole Electric – D" portion of this total.

b. Please provide additional information about the "Various Market Based" portion of this total.

A. The 12-month sum of projected capacity costs for 2020 ($560,376) is derived from the sum of capacity purchase costs and capacity sales revenues.

a. Given the variation in the actual monthly MW amounts taken under this agreement, the Seminole Electric-D 2020 estimated capacity sales revenue of [redacted].

b. The Various Market Based capacity sales revenue amount of [redacted] is the estimated capacity revenue to be received from market-based sales. This market varies significantly over time. [redacted]. Various capacity purchase costs of [redacted] include the estimated cost for a [redacted].

20190001.EI Staff Hearing Exhibits 00221

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is Director, Regulatory Affairs, Tampa Electric Company, and that she prepared or oversaw the preparation of responses to Staff's Third Set of Interrogatories (Nos. 17-18).

Dated at Tampa, Florida this 27th day of September, 2019.

Penelope Rusk

Sworn to and subscribed before me this 27th day of September, 2019.

Cynthia R. Kyle

Notary Public State of Florida
Cynthia R Kyle
My Commission GG 263876
Expires 03/01/2023

My Commission expires _____

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20190001-EI EXHIBIT: 100
PARTY: DEF
DESCRIPTION: Responses to OPC 5th ROGS Nos. 32-35, Issue 1C, Written Responses only.

EXHIBIT NO. 100

DOCKET NO: 20190001-EI

WITNESS: Jeffery Swartz

PARTY: DEF

DESCRIPTION:

DEF's Responses to OPC's Fifth Set of Interrogatories (Nos. 32-35) - Issue 1C. Written responses only, Attachments not included

DOCUMENTS:

Discovery Response

PROFFERED BY: DEF

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 20190001-EI Dated: September 10, 2019

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO CITIZENS' FIFTH SET OF INTERROGATORIES (NOS. 32-35)

Duke Energy Florida, LLC ("DEF") incorporates its objections filed contemporaneously with this request and responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Fifth Set of Interrogatories to DEF (Nos. 32-35) as follows:

INTERROGATORIES

Each of the following interrogatories may be answered by producing an Excel spreadsheet with the information or from which the information may be gleaned.

32. On an hourly basis, please provide an estimate of the number of MWh **not** produced as a result of the pressure plate installed on the low-pressure turbine at the Bartow Combined Cycle plant (Bartow) in 2018.

Answer:
Subject to and without waiving its objections, DEF responds as follows:

DEF disagrees with the premise that operation of Bartow with the pressure plate in place resulted in any "MWh not produced." DEF's decision to install the pressure plates in April 2017 allowed for operation free from forced outages during the remainder of 2017, all of 2018, and up to the Fall 2019 new blade installation outage. Therefore, the MWh **not** produced was eliminated or significantly minimized versus either additional forced outages or loss of the ST altogether while a long-term path forward was finalized. If the Company were to temporarily ignore this concept and assume that new L-0 blades were installed in April 2017 instead of the pressure plates and that those blades continued to operate at optimum performance without failure in 2018, the estimated MWh **not** produced in 2018 is 33,457 MWh, which was calculated as discussed below.

In order to provide a response, DEF had to create an estimate of the MWh not produced that relies on a number of assumptions, as described below. The question itself also omitted the baseline DEF was to use in order to calculate the MWh's not produced. Output from

the Bartow CC plant (as requested by OPC) depends on the operation configuration, Gas Turbine output and availability, use of PAG, duct-burning or evaporative cooling, and dispatch from the ECC. Moreover, regarding the ST itself, prior to the outage in February of 2017, operation of the Steam Turbine (ST) and its corresponding Megawatt output were a function of OEM specifications/guidelines relative to HP-inlet, IP-inlet and condenser backpressure restrictions (Periods 1-2), and eventually IP exhaust pressures (Periods 3-5), as was indicated in Mr. Swartz's previously submitted testimony Exhibit JS-1. As shown on that exhibit, the MW output expected from the ST as a result of the different operating restrictions was subject to fluctuation.

That all said, DEF developed the estimate by utilizing actual Energy Accounting (Gross and Net MW) meter data and calculated what the 95th percentile of hourly generation for any given month based on hourly outputs. Because combined cycle generation output varies significantly depending on ambient temperatures, the Company used the 95th percentile to estimate the hours the unit was dispatched to full load and could have possibly generated more MW's in those hours had the ST been operating with L-0 blades that allowed for operation at full pressures and optimum output (i.e., had the pressure plates not been installed). Depending on the configuration of the plant (4x1, 3x1, 2x1 or 1x1), the Company estimated a lost hourly MW of either 40 MW, 30 MW, 20 MW or 10 MW, respectively, for the hours where the Company may have wanted to generate more output out of Bartow CC economically. This calculation method value was part of the method used to answer Interrogatory No. 33 and Production of Documents No. 44.

33. Provide the estimated or actual replacement power costs for 2017 and 2018, required to replace the MWh **not** produced at Bartow due to the installation of the pressure plate in the low-pressure turbine. Identify all documents used to perform these calculations. For each month in 2019 where the pressure plate is or will be installed, please provide the estimated or actual replacement power costs required to replace the MWh **not** produced at Bartow due to the installation of the pressure plate in the low-pressure turbine.

Answer:
Subject to and without waiving its objections, as discussed in response to interrogatory number 32, DEF does not believe that operation of Bartow with the pressure plates installed resulted in any replacement power costs. However, subject to the issues and assumptions necessary to estimate the MWh "not produced" as discussed in response to interrogatory 32, DEF estimated replacement power costs required to replace the MWh **not** produced at Bartow due to the installation of the pressure plate in the low-pressure turbine from 4/10/2017 through 8/31/2019 is $1,168,613. DEF was able to estimate replacement power costs from the pressure plate commissioning date of 4/10/2017 through 8/31/2019. Given the number of variables that could impact the replacement power calculation, DEF does not have a method to forecast replacement power costs for the approximate 1-month time period from 9/1/2019 to the new L-0 blade installation outage which is scheduled to start in late September 2019.

34. Identify the highest cost power costs on an hourly basis for each hour in 2017 through year to date 2019, inclusive.

Answer:

Please see DEF's Response to OPC's Request to Produce Documents number 45.

35. Identify the highest cost purchased power costs on an hourly basis for each hour in 2017 through year to date 2019, inclusive.

Answer:

The attached spreadsheet bearing bates numbers DEF-19FL-FUEL-007282 Through DEF-19FL-FUEL-007352, contains the highest market purchased power cost for each hour that Duke Energy Florida purchased through 8/31/2019. These purchases include day ahead and real-time purchases by the power trading desk. These costs do not contain power costs purchased from long-term PPA contracts such as Shady Hills, Vandolah, or SOCO Franklin as those are either dispatched in real-time or scheduled day-ahead economically based on a production cost model forecast. The attachments are confidential. Copies have been provided to OPC pursuant to DEF's Motion for Temporary Protective Order.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 29th day of August, 2019, 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 32 through 35 of CITIZENS' FIFTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (Nos. 32-35) in Docket No. 20190001-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 29th day of AUGUST, 2019.

JVC Swartz

Jeffrey Swartz

DEANNA LEE CARVER
Commission # GG 236823
Expires July 18, 2022
Bonded Thru Troy Fain Insurance 800-385-7019

Deanna Lee Carver

Notary Public
State of Florida, at Large

My Commission Expires: July 18, 2022